Attachment 3

SAFETY SYSTEM FUNCTIONAL FAILURE RECONCILIATION PROJECT

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EXECUTIVE SUMMARY

One of the Reactor Oversight Process (ROP) performance indicators is the safety system functional failure (SSFF). It is defined in NEI 99-02, *Regulatory Assessment Performance Indicator Guideline,* as "the number of Licensee Event Reports (LERs) submitted each quarter in accordance with 10 CFR 50.73(a)(2)(v)." In early 2004, the Nuclear Regulatory Commission (NRC) staff identified what they believed to be a significant discrepancy between the total number of SSFFs being reported by the nuclear industry over the period 1999 through 2003, and the number its contractor, Idaho National Engineering and Environmental Laboratory (INEEL), believed to have occurred. At its monthly ROP meeting with the NRC staff, the NEI Safety Performance Assessment Task Force agreed to look into the apparent discrepancies and attempt to reconcile them.

The reconciliation project reviewed all of the LERs the NRC contractor and licensees had identified as SSFFs and made an independent assessment as to whether they were SSFFs. This assessment included discussions with licensees as to the circumstances surrounding the LERs in cases where discrepancies existed. The results were used to determine the consistency between contractor and licensees; the extent of over- or under-reporting; and what lessons could be learned to improve reporting.

The project team determined that there is some confusion regarding the reporting requirements under 10CFR50.73 which needs to be corrected. This confusion has resulted in some LERs not being reported and counted as SSFFs which the project team believes should have been, and some LERs being conservatively counted as SSFFs that did not meet the criteria. In total, industry appears to have slightly over-reported the number of SSFFs. Individually, some licensees have over-reported and some appear to have failed to report some SSFFs. It does not appear, however, that the under-reporting of these SSFFs would have resulted in the SSFF performance indicator crossing the GREEN-WHITE threshold for any licensee. The final decision on whether an LER should or should not be reported as an SSFF is the responsibility of the licensee.

Several lessons-learned were identified which should be used to clarify the reporting guidance in NUREG-1022, *Event Reporting Guidelines 10CFR 50.72 and 50.73,* and for enhancing the guidance in NEI 99-02.

BACKGROUND/SCOPE

One of the Reactor Oversight Process (ROP) performance indicators (PI) is the safety system functional failure (SSFF). It is defined in NEI 99-02, *Regulatory Assessment Performance Indicator Guideline,* as "the number of Licensee Event Reports (LERs) submitted each quarter in accordance with 10 CFR 50.73(a)(2)(v)." This regulation requires licensees to report:

"... (v) Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident... (vi) Events covered in paragraph (a)(2)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported pursuant to paragraph (a)(2)(v) of this section if redundant equipment in the same system was operable and available to perform the required safety function."

The Nuclear Regulatory Commission (NRC) contracts with the Department of Energy's Idaho National Engineering and Environmental Laboratory (INEEL) to review all LERs submitted pursuant to 10CFR50.73. INEEL examines each LER for numerous insights including industry trends, equipment performance, and verification of NRC reporting criteria. INEEL also assesses whether the LER should be included as an SSFF under the ROP PI program. Beginning with 1999 when data was first reported by licensees, INEEL has developed a list of about 553 LERs which it has categorized as meeting the definition of an SSFF.

During this period, however, licensees have reported approximately 413 SSFFs under the ROP PI program. The discrepancy between the number of licensee reported SSFFs and INEEL's count has been the subject of recent discussion by the NRC and the NEI Safety Performance Assessment Task Force (SPATF) that meet on a monthly basis.

The NRC staff noted that it was difficult to reconcile the differences for three reasons:

- 10 CFR 50.73 and the current guidance for preparing LERs, contained in NUREG-1022, *Event Reporting Guidelines 10CFR 50.72 and 50.73*, require licensees to focus their LERs on the "reportable condition." It does not require licensees to discuss or provide any supplementary information regarding other reporting requirements if they do not apply. Therefore, it is difficult to independently assess whether LERs should have reported under 10CFR50.73(a)(2)(v) without additional information or correspondence with the licensee. INEEL does not interact with the licensees in making its determination.

- The contractor codes LERs by the event date, while the SSFF is reported in the quarter the LER is filed, which can be as much as sixty days after the event.

- The current guidance for the PI program defined in NEI 99-02 does not require licensees to annotate their PI data submittals with the "LER Number" (Docket Number – Year – Sequential Number; e.g., 361-03-01). Therefore, it was not obvious which LERs licensees were reporting as SSFFs.

The NRC staff requested, and the NEI Safety Assessment Performance Task Force agreed, to conduct a reconciliation of the apparent discrepancies in data and report back to the NRC and industry with conclusions and recommendations.

PROJECT ACTIVITIES

A subcommittee of four industry experts in licensing and reportability was formed to perform an independent evaluation/reconciliation of the discrepancy in reporting between INEEL and licensees using 10CFR50.73(a)(2)(v) and NUREG-1022.

The NRC provided a database of the 553 LERs which INEEL had classified as SSFFs. In attempting to align these LERs with the SSFFs reported by licensees from 1999 through 2003, it became apparent that LER numbers would have to be gathered from licensees. This licensing listing of LERs counted as SSFFs revealed that a significant number of licensee reported SSFFs, about 74, were not included in the INEEL database.

As a result, the scope of the project had to be significantly expanded. It was inadequate just to determine which of the 553 INEEL LERs may have been missed by licensees. Rather, the effort had to reconcile both the INEEL-data and the licensee provided listing of 416 SSFFs, a grand total of 627 LERs. (See figure 1.)

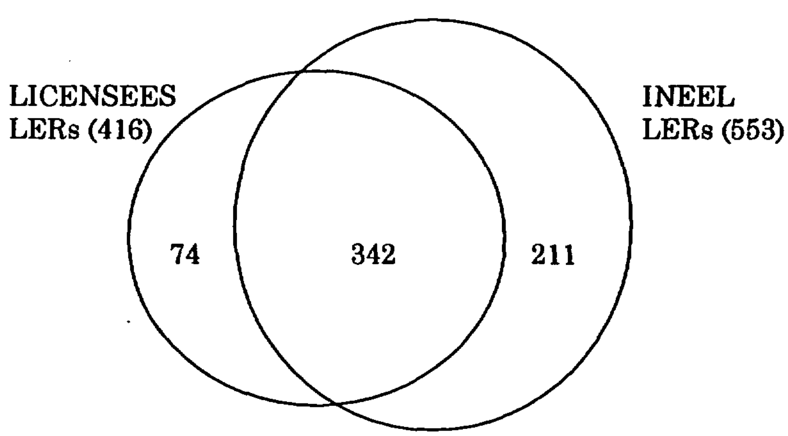


Figure 1

Both the INEEL data and the licensee listing were integrated into a single spreadsheet database. All 627 LERs would be individually examined and compared to the reportability guidance in NUREG-1022.

The team of four independent industry experts in reportability was convened. To test consistency among the reviewers, all LERs from four units were independently reviewed by the experts and the results compared. There was a high degree of consistency. During the project, the team leader performed random checks of other reviewers' LERs. In addition, when reviewers were unable to make a decision, they caucused with other team members. The combined data base was divided among the reviewers for analysis. No reviewer examined LERs from their own plant/company.

Each LER was reviewed and a reportability determination made. If the LER was particularly complex or if it was missing information, such that a reportability determination could not be made, the LER was preliminarily tagged as unresolved. Additional information on the LER and the condition or event circumstances was then sought directly from the licensee.

During the analysis the team determined that there were situations in which either INEEL, or the licensee, or both, had categorized an LER as an SSFF when it in fact was not an SSFF. Therefore, to include all possibilities, a total of six categories were needed (see figure 2):

1. Y – **[All Agree]** = Both INEEL and Licensee counted the LER as an SSFF, and the reconciliation review also agreed it was likely an SSFF.

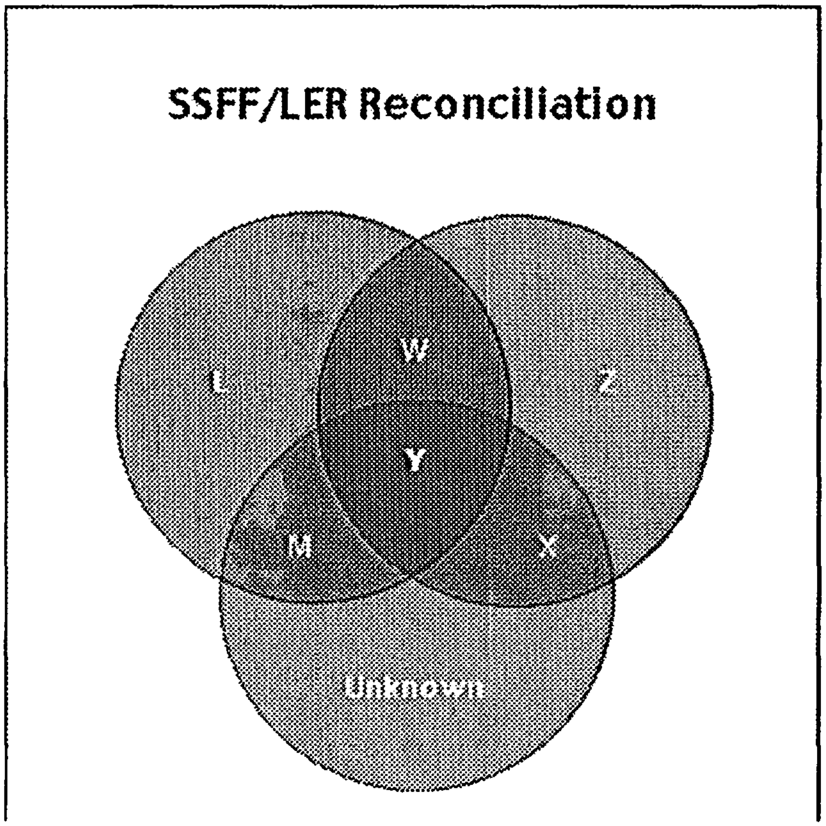
2. W – **[INEEL/Licensee both incorrect]** = Both INEEL and Licensee counted the LER as an SSFF, but the reconciliation review concluded it was likely not.

3. X – **[Licensee missed SSFF]** = INEEL concluded the LER was an SSFF, the Licensee did not report the LER as an SSFF, and the reconciliation review concluded the LER was likely an SSFF.

4. M – **[INEEL Missed SSFF]** = Licensee reported the LER as an SSFF, INEEL failed to identify LER as an SSFF, and the reconciliation review concluded the LER was likely an SSFF.

5. Z – **[INEEL incorrect]** = INEEL concluded LER was an SSFF, the Licensee did not report the LER as an SSFF, but the reconciliation review concluded the LER was likely not an SSFF.

6. L – **[Licensee incorrect]** = Licensee reported the LER as an SSFF, INEEL did not identify the LER as an SSFF, but the reconciliation review concluded the LER was likely NOT an SSFF.



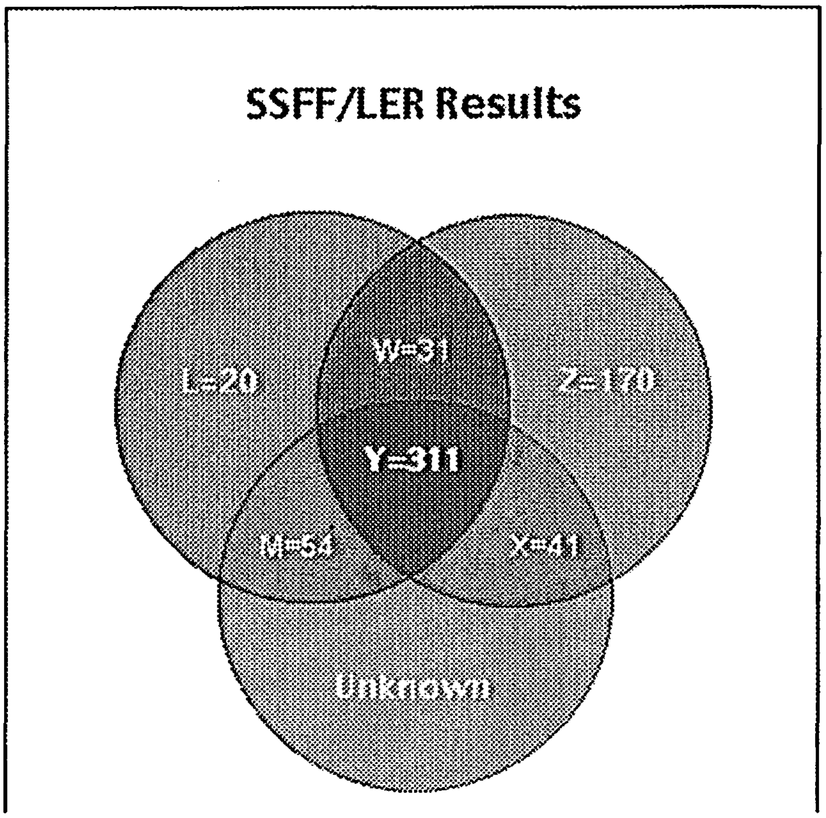
Category	INEEL	Licensee	Subcommittee
"Y"	SSFF	SSFF	SSFF
"W"	SSFF	SSFF	Likely not
"X"	SSFF	Not	Likely SSFF
"M"	Not	SSFF	Likely SSFF
"Z"	SSFF	Not	Likely not
"L"	Not	SSFF	Likely not
Unknown	There may be other LER SSFFs not reviewed		

Figure 2

At the conclusion of the project, some LER reportability dispositions were close calls. The reconciliation panel convened a special meeting and made a best judgment on the final disposition.

Because a final reconciliation was not made with each licensee, it would be inappropriate to use this report to conclude an individual licensee did or did not "properly report" SSFFs.

The analysis numerical results are provided in Figure 3.



Category	INEEL	Licensee	Subcommittee	# LERs	% LERs
"Y"	SSFF	SSFF	SSFF	311	49.6
"W"	SSFF	SSFF	Likely not	31	4.9
"X"	SSFF	Not	Likely SSFF	41	6.5
"M"	Not	SSFF	Likely SSFF	54	8.6
"Z"	SSFF	Not	Likely not	170	27.1
"L"	Not	SSFF	Likely not	20	3.2
Unknown	There may be other LER SSFFs not reviewed				

Figure 3

The reconciliation panel identified a total of 406 LERs which it believes should have been counted as SSFFs (categories Y, X, and M) over the 1999-2003 period. Industry reported a total of 416 SSFFs (categories Y, W, L and M). The panel's analysis suggests that industry correctly reported 365 SSFFs (categories Y and M). Industry also conservatively reported 51 LERs (categories L and W) that the panel does not believe were SSFFs. On the other hand, industry appears to have missed 41 LERs (category X) that INEEL and the panel believe should have been counted. Finally, of the 553 LERs counted by INEEL, the panel believes 352 should have been counted (categories Y and X), and that 201 were not SSFFs (categories W and Z). In addition, INEEL did not count 54 LERs that the panel and industry considered SSFFs (category M).

CONCLUSIONS AND RECOMMENDATIONS

A. Total Industry SSFF Reporting

On an industry level, it does not appear that industry is underreporting SSFFs. The reconciliation effort concludes that there were 406 SSFFs during the 1999-2003 time period, and that industry reported a total of 416. Of the 406 SSFFs, licensees correctly identified 365, or about 90%. (While they appear to have missed 41 SSFFs, they also over-reported 51.) The number of likely missed SSFFs has dropped from an average of 12 in 1999 and 2000, to 6 in 2002 and 5 in 2003. Likely misses were not systemically made by any individual plant. It does not appear that any plant would have crossed the green-white threshold based on these errors. Accuracy should continue to improve if the recommendations of this report are followed.

Recommendation

1. Distribute this report to all licensees to assist them in assessing the accuracy of their SSFF performance indicator reporting.

B. Limitations on INEEL data collection and analysis

INEEL is unable to perform detailed reviews of the circumstances involved in the LERs because they do not interact directly with the licensee. (The panel found this a necessary step in about 10% of the cases.) Complicating INEEL's ability to categorize the LERs as SSFFs are several factors. All of the relevant details may not have been provided in the LER. INEEL may not have reviewed an LER revision which provided the relevant information. INEEL apparently starts their data log based on telephone notifications made to the NRC under 10CFR50.72. If a report is subsequently retracted it may not be removed from the INEEL database. Finally, INEEL is hampered in comparing its results with those of licensees, in that licensees are not required to report the LER number in the ROP PI data submittal, and the licensee reports the SSFF in the quarter the LER is submitted whereas INEEL uses the event date.

Recommendations:

1. The NEI 99-02 guidance should be revised to require licensees to add the LER number in the comment field when it reports an SSFF.
2. Because INEEL does not interact with licensees directly, NRC should reconsider the value of having INEEL categorize LERs as SSFFs. This is a function which could be performed by residents who review every LER and have the opportunity to obtain the necessary details of a particular situation.

C. Improvements to Reportability Guidance

Both INEEL and licensees reported LERs that the panel believes are not SSFFs. Licensees and INEEL agreed on 31 LERs that the panel rejected (category W); INEEL identified 170 LERs that licensees did not report that the panel disagreed with (category Z); and licensees identified 20 LERs not counted by INEEL that the panel did not believe were SSSFs (category L). Three opportunities to improve the NUREG-1022 guidance were identified.

<u>Conditions Outside the Design Basis 10CFR50.73(a)(2)(ii)</u>

10CFR50.73(a)(2)(ii) requires licensees to report any condition where the plant or systems are outside the design basis of the plant. Typically, this consists of any event/condition where a system is not performing in verbatim accordance with the Safety Analysis Report.

However, NUREG-1022, Supplement 2, provides guidance that when evaluating issues under 50.73(a)(2)(v) the licensee is not to assume any additional failures/initiating events. NUREG-1022, Rev 2, Section 3.2.7, states in part:

> "*... In determining the reportability of an event or condition that affects a system, it is not necessary to assume an additional random single failure in that system; however, it is necessary to consider other existing plant conditions...*"

A significant number of the L, W, and Z LERs (those inappropriately counted by INEEL and/or licensees) involved reports under "design basis conditions," where an additional failure must be postulated, such as:

- Failure of the Appendix R safe shutdown panel
- Degradation of a High Energy Line Break barrier
- Susceptibility to a "smart short"

<u>Conditions Prohibited by the Plant's Technical Specifications 10CFR50.73(a)(2)(i)(B)</u>

10CFR50.73(a)(2)(i)(B) requires reporting of conditions prohibited by the Technical Specifications. If this condition also involves the inability of the system to perform its safety function (e.g., both trains inoperable), even if for a short period of time, then the event is also reportable under 10CFR50.73(a)(2)(v) (and 10CFR50.72(b)(3)(v) [8-hour ENS notification]).

NUREG-1022, Supplement 2, provides explicit guidance that such issues must be evaluated and reported. NUREG-1022, Rev 2, Section 3.2.7, states in part:

"... Whenever an event or condition exists where the system could have been prevented from fulfilling its safety function because of one or more reasons for equipment inoperability or unavailability, it is reportable under these criteria. This would include cases where one train is disabled and a second train fails a surveillance test..."

A significant number of the Category L, W, and Z LERs involved instances where a single train was not capable of performing its intended safety function. While licensees are required to consider the opposite train, and report under 10CFR50.73(a)(2)(v) if both trains are inoperable, licensees frequently do not discuss the status of the opposite train in the LER. This situation can directly affect the SSFF performance indicator reporting.

Preliminary feedback from the NRC was that INEEL may have assumed, when the inoperability existed for a long period of time, that the opposite train may have been out of service. Without being able to contact the licensee for additional information on the status of the opposite train, the as-submitted LER was inadequate to make a final determination. (We should also note that several instances existed when the licensee did, in fact, take the opposite train out for surveillance purposes, because it did not at the time realize that the first train was inoperable. These situations were category X, apparently missed SSFF.)

<u>T.S. 3.0.3 Conditions Allowed by the Plant's Technical Specifications</u>

A new issue with NUREG-1022 was identified during this project. We noted in reviewing several LERs that some plant safety systems have specific Technical Specification allowed outage times (AOT) for all trains to be out of service. If this all-train-out AOT is exceeded, the unit then goes to Technical Specification 3.0.3.

NUREG-1022 states in part (page 35),

"... STS 3.0.3 (ISTS LCO 3.0.3), or its equivalent, establishes requirements for actions when: (1) an LCO is not met and the associated ACTIONS are not met; (2) an associated ACTION is not provided, or (3) as directed by the associated ACTIONS themselves. Entry into STS 3.0.3 (ISTS LCO 3.0.3) or its equivalent is not necessarily reportable under this criterion. However, it should be considered reportable under this criterion if the condition is not corrected ***within an hour****, such that it is necessary to initiate actions to shutdown, cool down, etc..."* [emphasis added]

However, since the last revision of NUREG-1022, risk-informed Tech Specs have now been proposed which, in fact, would allow all trains to be out of service for a predefined period greater than an hour. For example, consider a three train HVAC system which supports the Control Room Ventilation System. Technical

Specifications allow all three Trains to be inoperable for 12 hours; after 12 hours the provisions of Tech Spec 3.0.3 apply. If a licensee finds that all three trains were inoperable for 11 hours, the event should not reportable under either 10CFR50.73(a)(2)(i)(B) (because TS were not exceeded) or 10CFR50.73(a)(2)(v) (because the plant was within the licensed configuration).

Recommendations:

1. Revise NUREG-1022, including illustrative examples, to clarify the circumstances for reporting 10CFR50.73(a)(2)(ii) "design criteria events/conditions" (such as Appendix R, etc.) under 10CFR50.73(a)(2)(v).

2. Revise NUREG-1022, including an illustrative example, to clarify that the reportability requirements of Technical Specification violations under 10CFR50.73(a)(2)(i)(B) may be reportable under 10CFR50.73(a)(2)(v) and that care must be taken to explicitly check and discuss the status of opposite trains for instances in which the entire system was unavailable.

3. Revise NUREG-1022 to clarify guidance for situations in which all trains of a system are allowed by technical specifications to be out of service for longer than an hour. There are two recommended changes:

   On page 35 (see citation above) insert the following bolded phrase: "*However, it should be considered reportable under this criterion if the condition is not corrected within an hour, **or the period specified in the technical specifications,** such that...*"

   On page 56 add a new bullet under "The following types of events or conditions generally are not reportable under these criteria:" which reads: "*inoperability of the entire system is permitted by the plant's Technical Specifications (i.e., plants Tech Specs allow all trains out of service for a specific time period and that period was not exceeded)*"

D. Identifying all applicable reporting requirements

The guidance in NUREG-1022 does not specifically require that licensees check all applicable reportability blocks. The LER form itself (NRC Form 366) does state "This report is submitted pursuant to the requirements of 10 CFR §: (Check all that apply)." However, the NUREG-1022 guidance says "check one or more blocks..." Our review indicated some licensees have only checked one box when more than one applies. Although NUREG-1022 encourages licensees to check one or more boxes, licensees have often interpreted the guidance to mean they only need check one box.

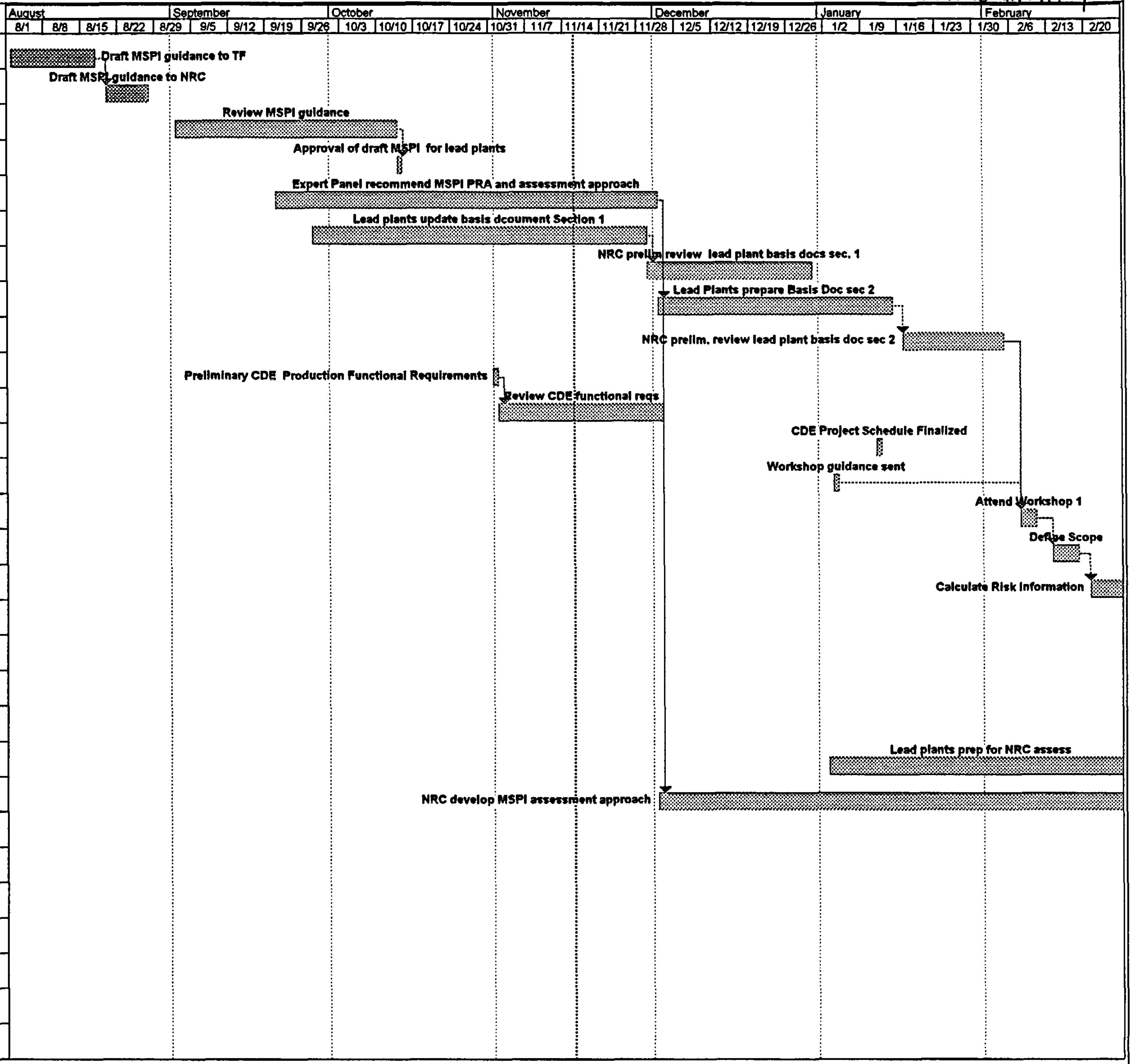
Recommendation:

1. Revise NUREG-1022 to explicitly require that all applicable reportability blocks be checked on NRC Form 366 Box 11.

Attachment 4

MSPI IMPLEMENTATION PLAN

ID	Task Name
1	Draft MSPI guidance to TF
2	Draft MSPI guidance to NRC
3	Review MSPI guidance
4	Approval of draft MSPI for lead plants
5	Expert Panel recommend MSPI PRA and assessment approach
6	Lead plants update basis dcoument Section 1
7	NRC prelim review lead plant basis docs sec. 1
8	Lead Plants prepare Basis Doc sec 2
9	NRC prelim. review lead plant basis doc sec 2
10	Preliminary CDE Production Functional Requirements
11	Review CDE functional reqs
12	CDE Project Schedule Finalized
13	Workshop guidance sent
14	Attend Workshop 1
15	Define Scope
16	Calculate Risk Information
17	Create Basis Doc
18	Basis Docments sent to NEI
19	Comparison of Basis Docs
20	Develop Admin Controls
21	Lead plants prep for NRC assess
22	NRC develop MSPI assessment approach
23	NRC assess Lead Plants
24	INPO provides failure tagging for production website
25	INPO delivers Workshop 2 software (ACCESS)
26	Attend Worshop 2
27	Revise Scope/Risk Info as needed
28	Calculate Historic Data
29	Revise basis document



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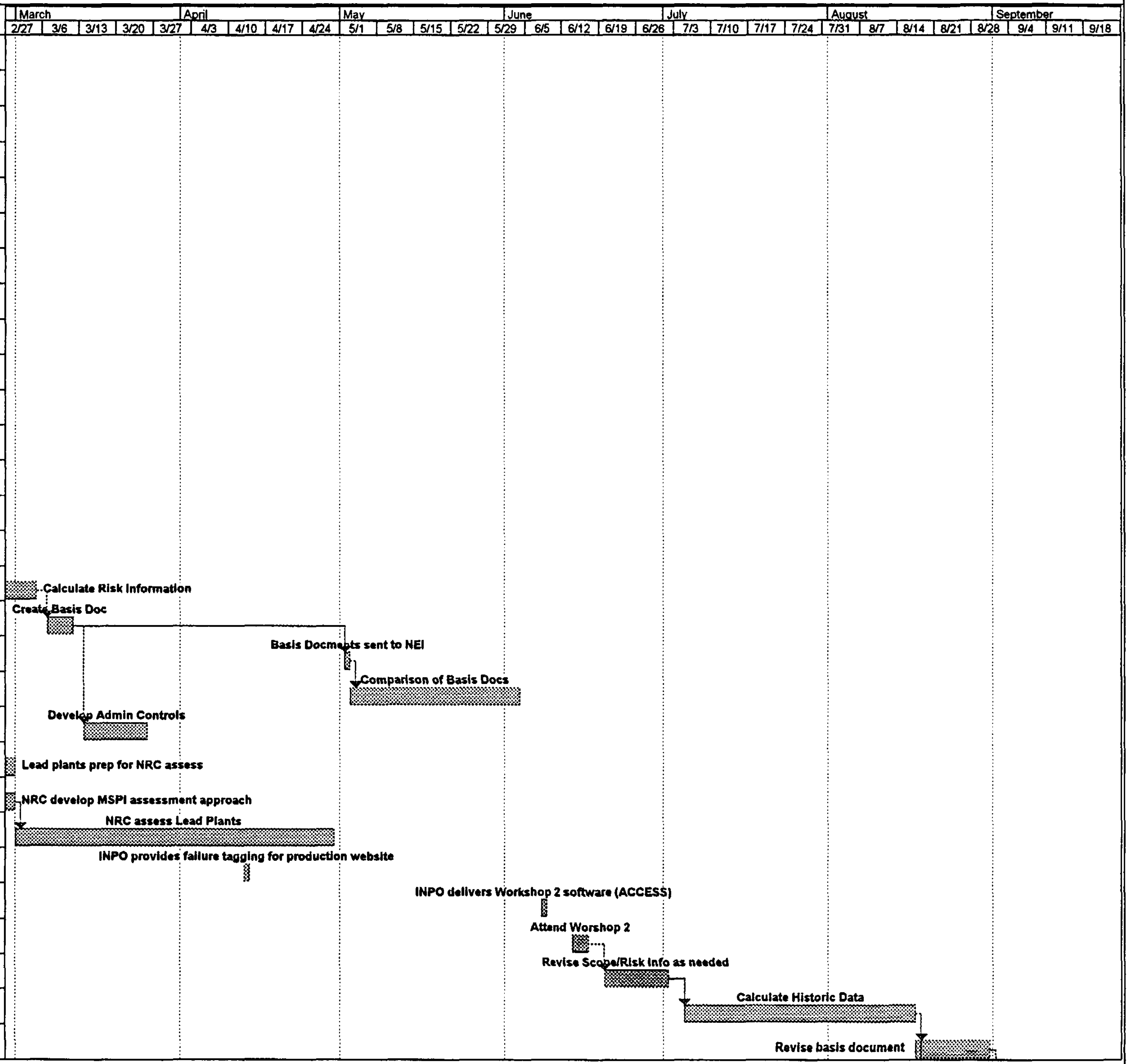

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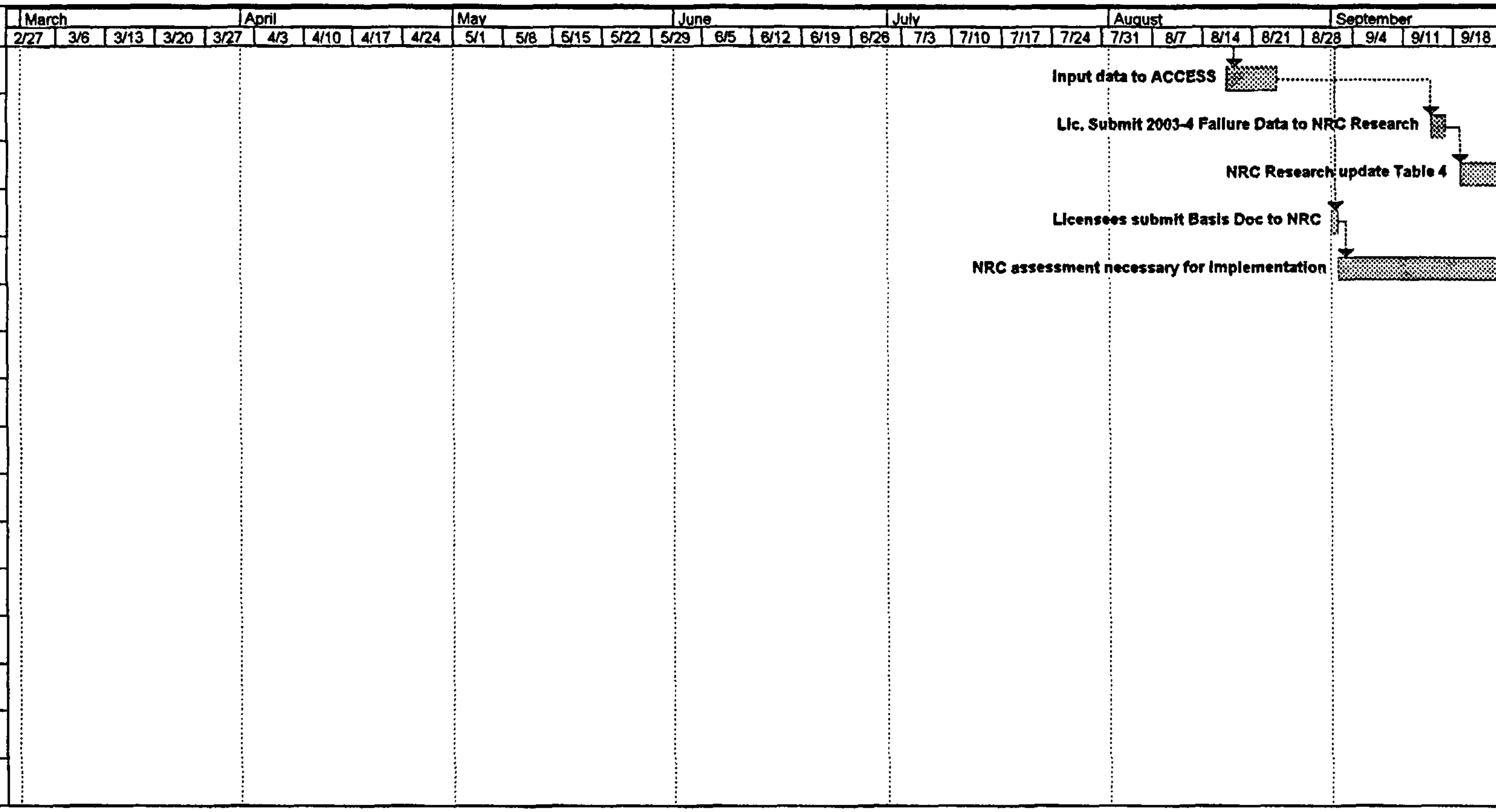
31	Lic. Submit 2003-4 Failure Data to NRC Research
32	NRC Research update Table 4
33	Licensees submit Basis Doc to NRC
34	NRC assessment necessary for implementation
35	NRC familiarization with CDE
36	Issue NEI 99-02 Revision
37	NRC issue RIS
38	NRC MSPI Communication Products available
39	CDE website testbed available
40	Workshop 3
41	Start MSPI implemenation
42	Last SSU reporting
43	INPO converts CDE for MSPI
44	Report MSPI data
45	Review MSPI Table 4



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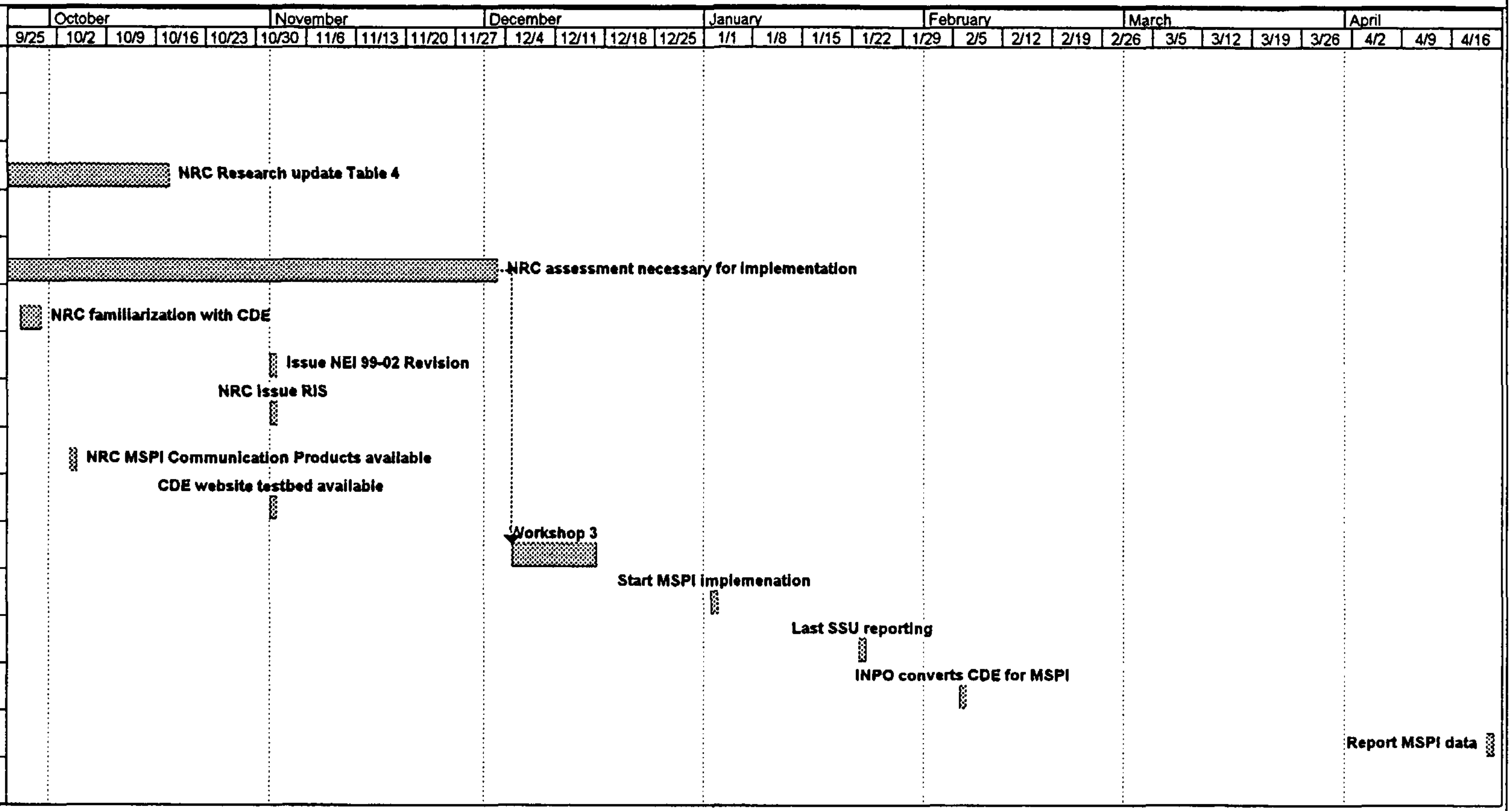

Attachment 5

MITIGATING SYSTEM PERFORMANCE INDEX

Purpose

The purpose of the Mitigating System Performance Index is to monitor the performance of selected systems based on their ability to perform risk-significant functions as defined herein. It is comprised of three elements - system unavailability, system unreliability and system component performance limits. The index is used to determine the cumulative significance of failures and unavailability over the monitored time period.

Indicator Definition

Mitigating System Performance Index (MSPI) is the sum of changes in a simplified core damage frequency evaluation resulting from differences in unavailability and unreliability relative to industry standard baseline values. The MSPI is supplemented with system component performance limits.

Unavailability is the ratio of the hours the train/system was unavailable to perform its risk-significant functions (as defined by PRA success criteria and mission times) due to planned and unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters. (Fault exposure hours are not included; unavailable hours are counted only from the time of discovery of a failed condition to the time the train's risk-significant functions are recovered.)

Unreliability is the probability that the train/system would not perform its risk-significant functions, as defined by PRA success criteria and mission times, when called upon during the previous 12 quarters.

Baseline values are the values for unavailability and unreliability against which current plant unavailability and unreliability are measured.

Component performance limit is a measure of degraded performance that indicates when the performance of a monitored component in an MSPI system is significantly lower than expected industry performance.

The MSPI is calculated separately for each of the following five systems for each reactor type.

BWRs

- emergency AC power system
- high pressure injection system (high pressure coolant injection, high pressure core spray, or feedwater coolant injection)
- reactor core isolation cooling(or isolation condenser)
- residual heat removal system (or the equivalent function as described in the Additional Guidance for Specific Systems section of Appendix F)

- cooling water support system (includes risk significant direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

PWRs

- emergency AC power system
- high pressure safety injection system
- auxiliary feedwater system
- residual heat removal system (or the equivalent function as described in the Additional Guidance for Specific Systems section of Appendix F)
- cooling water support system (includes risk significant direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

Data Reporting Elements

The following data elements are reported for each system

- Unavailability Index (UAI) due to unavailability for each monitored system
- Unreliability Index (URI) due to unreliability for each monitored system
- Systems that have exceeded their component performance limits

Calculation

The MSPI for each system is the sum of the UAI due to unavailability for the system plus URI due to unreliability for the system during the previous twelve quarters.

$MSPI = UAI + URI$

Component performance limits for each system are calculated as a maximum number of allowed failures (*Fm*) from the plant specific number of system demands and run hours. Actual numbers of equipment failures (*Fa*) are compared to these limits. This part of the indicator only applies to the green-white threshold.

See Appendix F for the calculation methodology for UAI due to system unavailability, URI due to system unreliability and system component performance limits.

The decision rules for assigning a performance color to a system are:

$$\text{IF}[(\text{MSPI} \le 1.0\text{e-}06) \text{ AND } (\text{Fa} \le \text{Fm})] \text{ THEN performance is GREEN}$$

$$\text{IF}\{[(\text{MSPI} \le 1.0\text{e-}06) \text{ AND } (\text{Fa} > \text{Fm})] \text{ OR } [(\text{MSPI} > 1.0\text{e-}06) \text{ AND } (\text{MSPI} \le 1.0\text{e-}05)]\}$$
$$\text{THEN performance is WHITE}$$

$$\text{IF}[(\text{MSPI} > 1.0\text{e-}05) \text{ AND } (\text{MSPI} \le 1.0\text{e-}04)] \text{ THEN performance is YELLOW}$$

$$\text{IF}(\text{MSPI} > 1.0\text{e-}04) \text{ THEN performance is RED}$$

Plant Specific PRA

The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter.

Specific requirements appropriate for this PRA application are defined in Appendix G. Any questions related to the interpretation of these requirements, the use of alternate methods to meet the requirements or the conformance of a plant specific PRA to these requirements will be arbitrated by an Industry/NRC expert panel. The decisions of this panel will be binding.

Definition of Terms

re-write paragraph

Risk Significant Functions: those at power functions, described in the Appendix F section "Additional Guidance for Specific Systems," that were determined to be risk-significant in accordance with NUMARC 93-01, or NRC approved equivalents (e.g., the STP exemption request). The risk significant system functions described in Appendix F, "Additional Guidance for Specific Systems" should be modeled in the plant's PRA/PSA. System and equipment performance requirements for performing the risk significant functions are determined from the PRA success criteria for the system.

Risk-Significant Mission Time: The mission time modeled in the PRA for satisfying the risk-significant function of reaching a stable plant condition where normal shutdown cooling is sufficient. Note that PRA models typically use a mission time of 24 hours. However, shorter intervals, as justified by analyses and modeled in the PRA, may be used.

Success criteria: The plant specific values of parameters the train/system is required to achieve to perform its risk-significant functions. Success criteria to be used are those documented in the plant specific PRA. Design Basis success criteria should be used in the case where the plant specific PRA has not documented alternative success criteria for use in the PRA.

Individual component capability must be evaluated against train/system level success criteria (e.g., a valve stroke time may exceed an ASME requirement, but if the valve still strokes in time to meet the PRA success criteria for the train/system, the component has not failed for the purposes of this indicator. This is because the risk-significant train/system function is still satisfied).

Clarifying Notes

Documentation

Each licensee will have the system boundaries, monitored components, and risk-significant functions and success criteria which differ from design basis readily available for NRC inspection on site. Design basis criteria do not need to be separately documented. Additionally, plant-specific information used in Appendix F should also be readily available for inspection. An acceptable format, listing the minimum required information, is provided in Appendix G.

Monitored Systems

Systems have been generically selected for this indicator based on their importance in preventing reactor core damage. The systems include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant accident, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. One risk-significant support function (cooling water support system) is also monitored. The cooling water support system monitors the risk significant cooling functions provided by service water and component cooling water, or their direct cooling water equivalents, for the four front-line monitored systems. No support systems are to be cascaded onto the monitored systems, e.g., HVAC room coolers, DC power, instrument air, etc.

Diverse Systems

Except as specifically stated in the indicator definition and reporting guidance, no credit is given for the achievement of a risk-significant function by an unmonitored system in determining unavailability or unreliability of the monitored systems.

Use of Plant-Specific PRA and SPAR Models

The MSPI is an approximation using information from a plant's PRA and is intended as an indicator of system performance. More accurate calculations using plant-specific PRAs or SPAR models cannot be used to question the outcome of the PIs computed in accordance with this guideline.

APPENDIX F

METHODOLOGIES FOR COMPUTING THE UNAVAILABILITY INDEX, THE UNRELIABILITY INDEX AND COMPONENT PERFORMANCE LIMITS

This appendix provides the details of three calculations: the System Unavailability Index, the System Unreliability Index, and component performance limits.

1. System Unavailability Index (UAI) Due to Train Unavailability

Unavailability is monitored at the train level for the purpose of calculating UAI. The process for calculation of the System Unavailability Index has three major steps:

- Identification of system trains
- Collection of plant data
- Calculation of UAI

The first of these steps is performed for the initial setup of the index calculation *(and if there are significant changes to plant configuration)*. The second step has some parts that are performed initially and then only performed again when a revision to the plant specific PRA is made or changes are made to the normal preventive maintenance practices. Other parts of the calculation are performed periodically to obtain the data elements reported to the NRC. This section provides the detailed guidance for the calculation of UAI.

1.1. Identification of System Trains

The identification of system trains is accomplished in two steps:

- Determine the system boundaries
- Identify the trains within the system

The use of simplified P&IDs can be used to document the results of this step and will also facilitate the completion of the directions in section 2.1.1 later in this document.

1.1.1. System Boundaries

The first step in the identification of system trains is to define the system boundaries. Include all components that are required to satisfy the risk-significant functions of the system. For fluid systems the boundary should extend from the water source (e.g., tanks, sumps, etc.) to the injection point (e.g., RCS, Steam Generators). For example, high-pressure injection may have both an injection mode with suction from the refueling water storage tank and a recirculation mode with suction from the containment sump. For Emergency AC systems, the system consists of all class 1E generators at the station.

Additional system specific guidance on system boundaries can be found in section 5 titled "Additional Guidance for Specific Systems" at the end of this appendix.

Some common conditions that may occur are discussed below.

Component Interface Boundaries

For water connections from systems that provide cooling water to a single monitored component, only the final connecting valve is included in the boundary. For example, for service water that provides cooling to support an AFW pump, only the final valve in the service water system that supplies the cooling water to the AFW system is included in the AFW system scope. This same valve is not included in the cooling water support system scope.

Water Sources and Inventory

Water tanks are not considered to be monitored components. As such, they do not contribute to URI. However, periods of insufficient water inventory contribute to UAI if they result in loss of the risk-significant train function for the required mission time. If additional water sources are required to satisfy train mission times, only the connecting active valve from the additional water source is considered as a monitored component for calculating UAI. If there are valves in the primary water source that must change state to permit use of the additional water source, these valves are considered monitored and should be included in UAI for the system.

Common Components

Some components in a system may be common to more than one system, in which case the unavailability of a common component is included in all affected systems. (However, see "Additional Guidance for Specific Systems" for exceptions; for example, the PWR High Pressure Safety Injection System.)

1.1.2. Identification of Trains within the System

Each monitored system shall then be divided into trains to facilitate the monitoring of unavailability.

A train consists of a group of components that together provide the risk significant functions of the system as explained in the "additional guidance for specific mitigating systems". ~~Fulfilling the risk-significant function of the system may require one or more trains of a system to operate simultaneously.~~ The number of trains in a system is generally determined as follows:

- for systems that provide cooling of fluids, the number of trains is determined by the number of parallel heat exchangers, or the number of parallel pumps, or the minimum number of parallel flow paths, whichever is fewer.
- for emergency AC power systems the number of trains is the number of class 1E emergency (diesel, gas turbine, or hydroelectric) generators at the station that are installed to power shutdown loads in the event of a loss of off-site power. (*For example, t*~~T~~his does not include the diesel generator dedicated to the BWR HPCS system, which is included in the scope of the HPCS system.)

Some components or flow paths may be included in the scope of more than one train. For example, one set of flow regulating valves and isolation valves in a three-pump, two-steam generator system are included in the motor-driven pump train with which they are electrically associated, but they are also included (along with the redundant set of valves) in the turbine-driven pump train. In these instances, the effects of unavailability of the valves should be reported in all affected trains. Similarly, when two trains provide flow to a common header, the effect of isolation or flow regulating valve failures in paths connected to the header should be considered in both trains.

Additional system specific guidance on train definition can be found in section 5 titled "Additional Guidance for Specific Systems" at the end of this appendix.

Additional guidance is provided below for the following specific circumstances that are commonly encountered:

- Cooling Water Support System Trains
- Swing Trains and Components Shared Between Units
- Maintenance Trains and Installed Spares

Cooling Water Support Systems and Trains

The cooling water function is typically accomplished by multiple systems, such as service water and component cooling water. A separate value for UAI will be calculated for each of the systems in this indicator and then they will be added together to calculate an overall UAI value.

In addition, cooling water systems are frequently not configured in discrete trains. In this case, the system should be divided into logical segments and each segment treated as a train. This approach is also valid for other fluid systems that are not configured in obvious trains. The way these functions are modeled in the plant-specific PRA will determine a logical approach for train determination. For example, if the PRA modeled separate pump and line segments (such as suction and discharge headers), then the number of pumps and line segments would be the number of trains.

Unit Swing trains and components shared between units

Swing trains/components are trains/components that can be aligned to any unit. To be credited as such, their swing capability must be modeled in the PRA to provide an appropriate Fussell-Vesely value.

Maintenance Trains and Installed Spares

Some power plants have systems with extra trains to allow preventive maintenance to be carried out with the unit at power without impacting the risk-significant function of the system. That is, one of the remaining trains may fail, but the system can still perform its risk significant function. To be a maintenance train, a train must not be needed to perform the system's risk significant function.

An "installed spare" is a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without impacting the risk-significant function of the system. To be an "installed spare," a component must not be needed for the system to perform the risk significant function.

Unavailability of the spare component/train is only counted in the index if the spare is substituted for a primary train/component. Unavailability is not monitored for a component/train when that component/train has been replaced by an installed spare or maintenance train.

1.2. Collection of Plant Data

Plant data for the UAI portion of the index includes:

- Actual train total unavailability data for the most recent 12 quarter period collected on a quarterly basis,
- Plant specific baseline planned unavailability, and
- Generic baseline unplanned unavailability.

Each of these data inputs to UAI will be discussed in the following sections.

1.2.1. Actual Train Unavailability

The Consolidated Data Entry (CDE) input for this parameter is Train Unavailable Hours. Critical hours are derived from reactor startup and shutdown occurrences. The actual calculation of Train Unavailability is performed by CDE.

Train Unavailability: Train unavailability is the ratio of the hours the train was unavailable to perform its risk-significant functions due to planned or unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters.

Train unavailable hours: The hours the train was not able to perform its risk significant function due to maintenance, testing, equipment modification, electively removed from service, corrective maintenance, or the elapsed time between the discovery and the restoration to service of an equipment failure or human error that makes the train unavailable (such as a misalignment) while the reactor is critical. Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's risk-significant functions. Unavailability must be by train; do not use average unavailability for each train because trains may have unequal risk weights.

Additional guidance on the following topics for counting train unavailable hours is provided below.

- Short Duration Unavailability
- Credit for Operator Recovery Actions to Restore the Risk-Significant Function

<u>Short Duration Unavailability</u>

Trains are generally considered to be available during periodic system or equipment realignments to swap components or flow paths as part of normal operations. Evolutions or surveillance tests that result in less than 15 minutes of unavailable hours per train at a time need not be counted as unavailable hours. Licensees should compile a list of surveillances or evolutions that meet this criterion and have it available for inspector review. ~~In addition, equipment misalignment or mispositioning which is corrected in less than 15 minutes need not be counted as unavailable hours.~~ The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact~~. If a licensee is required to take a component out of service for evaluation and corrective actions for greater than 15 minutes (for example, related to a Part 21 Notification), the unavailable hours must be included.~~

Credit for Operator Recovery Actions to Restore the Risk-Significant Functions

1. *During testing or operational alignment*:

Unavailability of a risk-significant function during testing or operational alignment need not be included if the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a designated operator[1] stationed locally for that purpose. Restoration actions must be contained in a written procedure[2], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions.

The individual performing the restoration function can be the person conducting the test and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the test may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

Under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires; or clearing tags). In addition, some manual operations of systems designed to operate automatically, such as manually controlling HPCI turbine to establish and control injection flow, are not virtually certain to be successful. These situations should be resolved on a case-by-case basis through the FAQ process.

2. *During Maintenance*

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[1] **Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.**

[2] **Including restoration steps in an approved test procedure.**

Unavailability of a risk-significant function during maintenance need not be included if the risk-significant function can be promptly restored either by an operator in the control room or by a designated operator[3] stationed locally for that purpose. Restoration actions must be contained in a written procedure[4], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at a proper location throughout the duration of the maintenance activity for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration of risk-significant functions that are virtually certain to be successful (i.e., probability nearly equal to 1).

The individual performing the restoration function can be the person performing the maintenance and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the maintenance activity may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

Under stressful chaotic conditions otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires, or clearing tags). These situations should be resolved on a case-by-case basis through the FAQ process.

3. During degraded conditions

No credit is allowed for operator actions during degraded conditions that render the train unavailable to perform its risk-significant functions.

1.2.2. Plant Specific Baseline Planned Unavailability

The *initial* baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values are expected to remain fixed unless the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value *should*~~can~~ be adjusted *to reflect the current maintenance practices, including low frequency maintenance evolutions. Some significant maintenance evolutions, such as EDG overhauls, are performed at a* intrv ~~*frequency*~~ *greater than the three year monitoring period (5 or 10 year intervals). The baseline planned unavailability should be revised as necessary the quarter prior to the* -10

[3] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

[4] Including restoration steps in an approved test procedure.

planned maintenance evolution and then removed when the evolution leaves the monitoring period. A comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability ~~may be~~*is* changed at the discretion of the licensee except that *it*~~they~~ shall be changed when changes in maintenance practices result in greater than a 25% change in *the baseline* planned unavailability. Revised values will be used in the calculation the quarter following their update.

To determine the initial value of planned unavailability:

1) Record the total train unavailable hours reported under the Reactor Oversight Process for 2002-2004.
2) Subtract any fault exposure hours still included in the 2002-2004 period.
3) Subtract unplanned unavailable hours.
4) Add any on-line overhaul hours and any other planned unavailability excluded in accordance with NEI 99-02. [5]
5) Add any planned unavailable hours for functions monitored under MSPI which were not monitored under SSU in NEI 99-02.
6) Subtract any unavailable hours reported when the reactor was not critical.
7) Subtract hours cascaded onto monitored systems by support systems. (However, do not subtract any hours already subtracted in the above steps.)
8) Divide the hours derived from steps 1-7 above by the total critical hours during 2002-2004. This is the baseline planned unavailability.

Support cooling planned unavailability baseline data is based on plant specific maintenance rule unavailability for years 2002-2004. Maintenance Rule practices do not typically differentiate planned from unplanned unavailability. However, best efforts will be made to differentiate planned and unplanned unavailability during this time period.

1.2.3. Generic Baseline Unplanned Unavailability

The unplanned unavailability values are contained in Table 1 and remain fixed. They are based on ROP PI industry data from 1999 through 2001. (Most baseline data used in PIs come from the 1995-1997 time period. However, in this case, the 1999-2001 ROP data are preferable, because the ROP data breaks out systems separately. Some of the industry 1995-1997 INPO data combine systems, such as HPCI and RCIC, and do not include PWR RHR. It is important to note that the data for the two periods is very similar.)

[5] Note: The plant-specific PRA should model significant on-line overhaul hours.

Table 1. Historical Unplanned Unavailability Train Values
(Based on ROP Industry wide Data for 1999 through 2001)

SYSTEM	UNPLANNED UNAVAILABILITY/TRAIN
EAC	1.7 E-03
PWR HPSI	6.1 E-04
PWR AFW (TD)	9.1 E-04
PWR AFW (MD)	6.9 E-04
PWR AFW (DieselD)	7.6 E-04
PWR (except CE) RHR	4.2 E-04
CE RHR	1.1 E-03
BWR HPCI	3.3 E-03
BWR HPCS	5.4 E-04
BWR FWCI	*Need a value for FWCI*
BWR RCIC	2.9 E-03
BWR IC	Need a value for isolation condensers
BWR RHR	1.2 E-03
Support Cooling	Use plant specific Maintenance Rule data for 2002-2004

Unplanned unavailability baseline data for the support cooling systems should be developed from plant specific Maintenance Rule data from the period 2002-2004. Maintenance Rule practices do not typically differentiate planned from unplanned unavailability. However, best efforts will be made to differentiate planned and unplanned unavailability during this time period. NOTE: The sum of planned and unplanned unavailability cannot exceed the total unavailability.

1.3. Calculation of UAI

The specific formula for the calculation of UAI is provided in this section. Each term in the formula will be defined individually and specific guidance provided for the calculation of each term in the equation. Required inputs to the INPO Consolidated Data Entry (CDE) System will be identified.

Calculation of System UAI due to train unavailability is as follows:

$$UAI = \sum_{j=1}^{n} UAIt_j \qquad \text{Eq. 1}$$

where the summation is over the number of trains (n) and UAI_t is the unavailability index for a train.

Calculation of UAI_t for each train due to actual train unavailability is as follows:

$$UAI_t = CDF_p \left[\frac{FV_{UAp}}{UA_p} \right]_{max} (UA_t - UABL_t) \quad , \qquad \text{Eq. 2}$$

where:

CDF_p is the plant-specific Core Damage Frequency,

FV_{UAp} is the train-specific Fussell-Vesely value for unavailability,

UA_P is the plant-specific PRA value of unavailability for the train,

UA_t is the actual unavailability of train t, defined as:

$$UA_t = \frac{\text{Unavailable hours during the previous 12 quarters while critical}}{\text{Critical hours during the previous 12 quarters}}$$

and, determined in section 1.2.1

UA_{BLt} is the historical baseline unavailability value for the train (sum of planned unavailability determined in section 1.2.2 and unplanned unavailability in section1.2.3)

Calculation of the quantities in equation 2 are discussed in the following sections.

1.3.1. Calculation of Core Damage Frequency (CDFp)

The Core Damage Frequency is a CDE input value. The required value is the <u>internal events, average maintenance,</u> at power value. Internal flooding and fire are not included in this calculated value. In general, all inputs to this indicator from the PRA are calculated from the internal events model only.

1.3.2. Calculation of [FV/UA]max for each train

FV and UA are separate CDE input values. Equation 2 includes a term that is the ratio of a Fussell-Vesely importance value divided by the related unavailability. This ratio is calculated for each train in the system and both the FV and UA are CDE inputs. (It may be recognized that the quantity [FV/UA] multiplied by the CDF is the Birnbaum importance measure, which is used in section 2.3.3.)

Calculation of these quantities is generally complex, but in the specific application used here, can be greatly simplified.

The simplifying feature of this application is that only those components (or the associated basic events) that can make a train unavailable are considered in the performance index. Components within a train that can each make the train unavailable are logically equivalent and the ratio FV/UA is a constant value for any basic event in that train. It can also be shown that for a given component or train represented by multiple basic events, the ratio of the two values for the component or train is equal to the ratio of values for any basic event within the train. Or:

$$\frac{FV_{be}}{UA_{be}} = \frac{FVUAp}{UAp} = \text{Constant}$$

Thus, the process for determining the value of this ratio for any train is to identify a basic event that fails the train, determine the unavailability for the event, determine the associated FV value for the event and then calculate the ratio. Use the basic event in the train with the largest failure probability (hence the maximum notation on the bracket) to minimize the effects of truncation on the calculation.

Some systems have multiple modes of operation, such as PWR HPSI systems that operate in injection as well as recirculation modes. In these systems all monitored components are not logically equivalent; unavailability of the pump fails all operating modes while unavailability of the sump suction valves only fails the recirculation mode. In cases such as these, if unavailability events exist separately for the components within a train, the appropriate ratio to use is the maximum.

Cooling Water and Service Water System $[FV/UA]_{max}$ Values

Component Cooling Water Systems (CCW) and Service Water Systems (SWS) at some nuclear stations contribute to risk in two ways. First, the systems provide cooling to equipment used for the mitigation of events and second, the failures (and unavailability) in the systems may also result in the initiation of an event. The contribution to risk from failures to provide cooling to other plant equipment is modeled directly through dependencies in the PRA model. However, the contribution due to event initiation is treated in three general ways in current PRAs:

1) *The use of linked initiating event fault trees for these systems*
2) *Fault tree solutions are generated for these systems external to the PRA and the calculated value is used in the PRA as a point estimate*
3) *A point estimate value is generated for the initiator using industry and plant specific event data and used in the PRA.*

If a PRA uses the first modeling option, then the FV values calculated will reflect the total contribution to risk due to train unavailability, ***as long the same basic event is used in the initiator and mitigation fault trees****. If different basic events are used, the FV values for the initiator tree basic event and the mitigation tree basic event should be added.*

If a linked initiating event fault tree is the modeling approach taken, then no additional corrections to the FV values is required. This section will outline a method to be used to if linked initiating event fault trees are not used.

The corrected $[FV/UA]_{max}$ for a train a is calculated from the expression:

$$[FV / UA]\text{max} = [(FVa + FVie * FVsa) / UA]$$

Where:

FVa is the Fussell-Vesely for CDF for train a as calculated from the PRA Model. This does not include any contribution from initiating events.

FVie is the Fussell-Vesely contribution for the initiating event in question (e.g. loss of service water).

*FVsa is the Fussell-Vesely **within the system fault tree only** for train a (i.e. the ratio of the sum of the cut sets in the fault tree solution in which that train appears to the overall system failure probability).*

FV and UA are separate CDE input values.

2. System Unreliability Index (URI) Due to Component Unreliability

Calculation of the URI is performed in three major steps:

- Identification of the monitored components for each system
- Collection of plant data
- Calculation of the URI

Only the most risk significant components in each system are monitored to minimize the burden for each utility. It is expected that most, if not all the components identified for monitoring are already being monitored for failure reporting to INPO and are also monitored in accordance with the maintenance rule.

2.1. Identify Monitored Components

Monitored Component: A component whose failure to change state or remain running renders the train incapable of performing its risk-significant functions. In addition, all pumps and diesels in the monitored systems are included as monitored components.

The identification of monitored components involves the use of the system boundaries and success criteria, identification of the components to be monitored within the system boundary and the scope definition for each component.

2.1.1. System Boundaries and Success Criteria

The system boundaries developed in section 1.1.1 should be used to complete the steps in the following section.

For each system, the at power risk significant functions described in the Appendix F section "Additional Guidance for Specific Systems," that were determined to be risk-significant in accordance with NUMARC 93-01, or NRC approved equivalents (e.g., the STP exemption request) shall be identified. Success criteria used in the PRA shall then be identified for these functions.

If the licensee has chosen to use success criteria documented in the plant specific PRA different from design basis success criteria, examples of plant specific performance factors that may be used to identify the required capability of the train/system to meet the risk-significant functions are provided below.

- Actuation
    - o Time

  - o Auto/manual
  - o Multiple or sequential
- Success requirements
  - o Numbers of components or trains
  - o Flows
  - o Pressures
  - o Heat exchange rates
  - o Temperatures
  - o Tank water level
- Other mission requirements
  - o Run time
  - o State/configuration changes during mission
- Accident environment from internal events
  - o Pressure, temperature, humidity
- Operational factors
  - o Procedures
  - o Human actions
  - o Training
  - o Available externalities (e.g., power supplies, special equipment, etc.)

If the licensee has chosen to use design basis success criteria in the PRA, it is not required to separately document them other than to indicate that is what was used.

If success criteria for a system vary by function or initiator, the most restrictive set will be used for the MSPI.

2.1.2. Selection of Components

For unreliability, use the following process for determining those components that should be monitored. These steps should be applied in the order listed.

1) INCLUDE all pumps and diesels.
2) Identify all AOV's and MOV's that change state to achieve the risk significant functions for the system as potential monitored components. Check valves, solenoid valves and manual valves are not included in the index.
    a. INCLUDE those valves from the list of valves from step 2 whose failure alone can fail a train. The success criteria used to identify these valves are those identified in the previous section. (See Figure F-5)
    b. INCLUDE redundant valves from the list of valves from step 2 within a multi-train system, whether in series or parallel, where the failure of both valves would prevent all trains in the system from performing a risk-significant function. The success criteria used to identify these valves are those identified in the previous section.(See Figure F-5)
    c. EXCLUDE those valves from steps a) and b) above whose Birnbaum importance, (See section 2.3.3) as calculated in this appendix, is less than

1.0e-06. This rule is applied at the discretion of the individual plant. A balance should be considered in applying this rule between the goal to minimize the number of components monitored and having a large enough set of components to have an adequate data pool.

3) INCLUDE components that cross tie monitored systems between units (i.e. Electrical Breakers and Valves) if they are modeled in the PRA.

2.1.3. Definition of Component Boundaries

Table 2 defines the boundaries of components, and Figures F-1, F-2, F-3 and F-4 provide examples of typical component boundaries as described in Table 2.

Table 2. Component Boundary Definition

Component	Component boundary
Diesel Generators	The diesel generator boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local), cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, circuit breaker for supply to safeguard buses and their associated local control circuit (coil, auxiliary contacts, wiring and control circuit contacts, and breaker closure interlocks) .
Motor-Driven Pumps	The pump boundary includes the pump body, motor/actuator, lubrication system cooling components of the pump seals, the voltage supply breaker, and its associated local control circuit (coil, auxiliary contacts, wiring and control circuit contacts).
Turbine-Driven Pumps	The turbine-driven pump boundary includes the pump body, turbine/actuator, lubrication system (including pump), extractions, turbo-pump seal, cooling components, and local turbine control system including the control valve (speed).
Motor-Operated Valves	The valve boundary includes the valve body, motor/actuator, the voltage supply breaker (both motive and control power) and its associated local open/close circuit (open/close switches, auxiliary and switch contacts, and wiring and switch energization contacts).
Air-Operated Valves	The valve boundary includes the valve body, the air operator, associated solenoid-operated valve, the power supply breaker or fuse for the solenoid valve, and its associated control circuit (open/close switches and local auxiliary and switch contacts).

For control and motive power, only the last relay, breaker or contactor necessary to power or control the component is included in the monitored component boundary. For example, if an ESFAS signal actuates a MOV, only the relay that receives the ESFAS signal in the control circuitry for the MOV is in the MOV boundary. No other portions of the ESFAS are included.

Each plant will determine its monitored components and support components and have them available for NRC inspection.

2.2. Collection of Plant Data

Plant data for the URI includes:

- Demands and run hours
- Failures

2.2.1. Demands and Run Hours

Start demand: Any demand for the component to successfully start (includes valve and breaker demands to open or close) to perform its risk-significant functions, actual or test. (Exclude post maintenance test demands, unless in case of a failure the cause of failure was independent of the maintenance performed. In this case the demand will be counted as well as the failure.) The number of demands is:

- the number of actual ESF demands plus
- the number of estimated test demands plus
- the number of estimated operational/alignment demands.

The number of estimated demands can be derived based on the number of times a procedure or maintenance activity is performed, or based on historical data over a year or more averaged to provide a quarterly average. It is also permissible to use the actual number of test and operational demands.

An update to the estimated demands is required if a change to the basis for the estimated demands results in a >25% change in the estimate. The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE. Some monitored valves will include a throttle function as well as open and close functions. One should not include every throttle movement of a valve as a counted demand. Only the initial movement of the valve should be counted as a demand.

Some components such as valves may need to be in different states at different times to fulfill the risk significant function of the monitored system. In this case each change of state is a demand. An example would be a minimum flow valve that needs to open on the pump start (one demand) then close (second demand) to prevent a diversion path or a valve needs to open(one demand) for the initial water supply then close (second demand) while another water supply valve opens.

Post maintenance tests: Tests performed following maintenance but prior to declaring the train/component operable, consistent with Maintenance Rule implementation.

Load/Run demand: Applicable to EDG only. Any demand for the EDG output breaker to close, given that the EDG has successfully started and achieved rated speed and voltage. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Run Hours: The number of run hours is:

- the number of actual ESF run hours plus

- the number of estimated test run hours plus
- the number of estimated operational/alignment run hours.

The number of estimated run hours can be derived based on the number of times a procedure or maintenance activity is performed, or based on historical data over a year or more averaged to provide a quarterly average. It is also permissible to use the actual number of test and operational run hours. Run hours include the first hour of operation of a component. An update to the estimated run hours is required if a change to the basis for the estimated hours results in a >25% change in the estimate. The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE.

2.2.2. Failures

EDG failure to start: A failure to start includes those failures up to the point the EDG has achieved rated speed and voltage. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to load/run: Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform its risk-significant functions. This failure mode is treated as a demand failure for calculation purposes. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to run: Given that it has successfully started and loaded and run for an hour, a failure of an EDG to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Pump failure on demand: A failure to start and run for at least one hour is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Pump failure to run: Given that it has successfully started and run for an hour, a failure of a pump to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Valve failure on demand: A failure to transfer to the required risk significant state (open, close, or throttle to the desired position as applicable) is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Breaker failure on demand: A failure to transfer to the required risk significant state (open or close as applicable) is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Treatment of Demand and Run Failures

Failures of monitored components on demand or failures to run, either actual or test are included in unreliability. Failures on demand or failures to run while not critical are included unless an evaluation determines the failure would not have affected the ability of the component to perform its risk-significant at power function. In no case can a postulated action to recover a failure be used as a justification to exclude a failure from the count.

Treatment of Degraded Conditions Capable of Being Discovered By Normal Surveillance Tests

Normal surveillance tests are those tests that are performed at a frequency of a refueling cycle or more frequently.

Degraded conditions, even if no actual demand or test existed, that render a monitored component incapable of performing its risk-significant functions are included in unreliability as a demand and a failure. The appropriate failure mode must be accounted for. For example, for valves, a demand and a demand failure would be assumed and included in URI. For pumps and diesels, if the degraded condition would have prevented a successful start, a demand and a failure is included in URI, but there would be no run time hours or run failures. If it was determined that the pump/diesel would start and load run, but would fail sometime during the 24 hour run test or its surveillance test equivalent, the evaluated failure time would be included in run hours and a run failure would be assumed. A start demand and start failure would not be included. If a running component is secured from operation due to observed degraded performance, but prior to failure, then a run failure shall be counted unless evaluation of the condition shows that the component would have continued to operate for the risk-significant mission time starting from the time the component was secured. Unavailable hours are included for the time required to recover the risk-significant function(s) and only while critical.

Degraded conditions, or actual unavailability due to mispositioning of non-monitored components that render a train incapable of performing its risk-significant functions are only included in unavailability for the time required to recover the risk-significant function(s) and only while critical.

Loss of risk significant function(s) is assumed to have occurred if the established success criteria have not been met. If subsequent analysis identifies additional margin for the success criterion, future impacts on URI or UAI for degraded conditions may be determined based on the new criterion. However, the current quarter's URI and UAI must be based on the success criteria of record at the time the degraded condition is discovered. ~~If subsequently, new success criteria are to be used, they must be included in the PRA and the MSPI basis document.~~ *If the new success criteria causes a revision to the PRA affecting the numerical results (i.e. CDF and FV), then the change must be included in the PRA model and the appropriate new values calculated and incorporated in the MSPI Basis Document prior to use in the calculation of URI and UAI. If the change in success criteria has no affect on the numerical results of the PRA (representing only a change in margin) then only the MSPI Basis Document need be revised prior to using the revised success criteria.*

If the degraded condition is not addressed by any of the pre-defined success criteria, an engineering evaluation to determine the impact of the degraded condition on the risk-significant function(s) should be completed and documented. The use of component failure analysis, circuit analysis, or event investigations is acceptable. Engineering judgment may be used in conjunction with analytical techniques to determine the impact of the degraded condition on the risk-significant function. The engineering evaluation should be completed as soon as practicable. If it cannot be completed in time to support submission of the PI report for the current quarter, the comment field shall note that an evaluation is pending. The evaluation must be completed in time to accurately account for unavailability/unreliability in the next quarterly report. Exceptions to this guidance are expected to be rare and will be treated on a case-by-case basis. Licensees should identify these situations to the resident inspector.

Treatment of Degraded Conditions Not Capable of Being Discovered by Normal Surveillance Tests

These failures or conditions are usually of longer exposure time. Since these failure modes have not been tested on a regular basis, it is inappropriate to include them in the performance index statistics. These failures or conditions are subject to evaluation through the inspection process. Examples of this type are failures due to pressure locking/thermal binding of isolation valves, blockages in lines not regularly tested, unforeseen sequences not incorporated into the surveillance test, or inadequate component sizing/settings under accident conditions (not under normal test conditions). While not included in the calculation of the index, they should be reported in the comment field of the PI data submittal.

would have

Failures of Non-Monitored Components

Failures of SSC's that are not included in the performance index will not be counted as a failure or a demand. Failures of SSC's that cause an SSC within the scope of the performance index to fail will not be counted as a failure or demand. An example could be a manual suction isolation valve left closed which causes a pump to fail. This would not be counted as a failure of the pump. Any mispositioning of the valve that caused the train to be unavailable would be counted as unavailability from the time of discovery. The significance of the mispositioned valve prior to discovery would be addressed through the inspection process.

2.3. Calculation of URI

Unreliability is monitored at the component level and calculated at the system level. Calculation of system URI due to changes in component unreliability is as follows:

$$URI = CDFp \sum_{j=1}^{m} \left[\frac{FVURcj}{URpcj} \right]_{\max} (URBcj - URBLcj) \qquad \text{Eq. 3}$$

Where the summation is over the number of monitored components (m) in the system, and:

CDF_p is the plant-specific Core Damage Frequency,

FV_{URc} is the component-specific Fussell-Vesely value for unreliability,

UR_{Pc} is the plant-specific PRA value of component unreliability,

UR_{Bc} is the Bayesian corrected component unreliability for the previous 12 quarters,

and

UR_{BLc} is the historical industry baseline calculated from unreliability mean values for each monitored component in the system. The calculation is performed in a manner similar to equation 6 in section 2.3.4 below using the industry average values in Table 4.

The following sections will discuss the calculation of each of the terms in equation 3.

2.3.1. Calculation of Core Damage Frequency (CDFp)

The Core Damage Frequency is a CDE input value. The required value is the internal events average maintenance at power value. Internal flooding and fire are not included in this calculated value. In general, all inputs to this indicator from the PRA are calculated from the internal events model only.

2.3.2. Calculation of [FV/UR]max

The FV, UR and common cause adjustment values developed in this section are separate CDE input values.

Equation 3 includes a term that is the ratio of a Fussell-Vesely importance value divided by the related unreliability. The calculation of this ratio is performed in a similar manner to the ratio calculated for UAI, except that the ratio is calculated for each monitored component. Two additional factors need to be accounted for in the unreliability ratios that were not needed in the unavailability ratios, the contribution to the ratio from common cause failure events and the possible contribution from cooling water initiating events. The discussion will start with the calculation of the initial ratio and then proceed with options for adjusting this value to account for the additional two factors.

It can be shown that for a given component represented by multiple basic events, the ratio of the two values for the component is equal to the ratio of values for any basic event representing the component. Or:

$$\frac{FVbe}{URbe} = \frac{FVURc}{URPc} = \text{Constant}$$

Note that the constant value may be different for the unreliability ratio and the unavailability ratio because the two types of events are frequently not logically equivalent. For example recovery actions may be modeled in the PRA for one but not the other.

Thus, the process for determining the initial value of this ratio for any component is to identify a basic event that fails the component (excluding common cause events), determine the failure probability for the event, determine the associated FV value for the event and then calculate the ratio, $[FV/UR]_{ind}$, where the subscript refers to independent failures. Use the basic event for the component and its associated FV value that results in the largest *[FV/UR]* ratio. This will typically be the event with the largest failure probability to minimize the effects of truncation on the calculation.

It is typical, given the component scope definitions in Table 2, that there will be several plant components modeled separately in the plant PRA that make up the MSPI component definition. For example, it is common that an MOV, the actuation relay for the MOV and the power supply breaker for the MOV are separate components in the plant PRA. Ensure that the basic events related to all of these individual components are considered when choosing the appropriate *[FV/UR]* ratio.

Cooling Water and Service Water System $[FV/UR]_{ind}$ Values

Component Cooling Water Systems (CCW) and Service Water Systems (SWS) at some nuclear stations contribute to risk in two ways. First, the systems provide cooling to equipment used for the mitigation of events and second, the failures in the systems may also result in the initiation of an event. The contribution to risk from failures to provide cooling to other plant equipment is modeled directly through dependencies in the PRA model. However, the contribution due to event initiation is treated in three general ways in current PRAs:

1) The use of linked initiating event fault trees for these systems
2) Fault tree solutions are generated for these systems external to the PRA and the calculated value is used in the PRA as a point estimate
3) A point estimate value is generated for the initiator using industry and plant specific event data and used in the PRA.

If a PRA uses the first modeling option, then the FV values calculated will reflect the total contribution to risk for a component in the system, **as long the same basic event is used in the initiator and mitigation fault trees.** If different basic events are used, the FV values for the initiator tree basic event and the mitigation tree basic event should be added.

If a linked initiating event fault tree is the modeling approach taken, then no additional corrections to the FV values is required. This section will outline a method to be used to if linked initiating event fault trees are not used.

The corrected $[FV/UR]_{ind}$ for a component C is calculated from the expression:

$$[FV/UR]_{ind} = [(FVc + FVie * FVsc)/UR]$$

Where:

FVc is the Fussell-Vesely for CDF for component C as calculated from the PRA Model. This does not include any contribution from initiating events.

$FVie$ is the Fussell-Vesely contribution for the initiating event in question (e.g. loss of service water).

$FVsc$ is the Fussell-Vesely **within the system fault tree only** for component C (i.e. the ratio of the sum of the cut sets in the fault tree solution in which that component appears to the overall system failure probability).

FV and UR are separate CDE input values.

Including the Effect of Common Cause in $[FV/UR]_{max}$

Changes in the independent failure probability of an SSC imply a proportional change in the common cause failure probability, even though no actual common cause failures have occurred. The impact of this effect on URI is considered by including a multiplicative adjustment to the $[FV/UR]_{ind}$ ratio developed in the section above. This multiplicative factor is a CDE input value.

Two methods are provided for including this effect, a simple generic approach that uses bounding generic adjustment and a more accurate plant specific method that uses values derived from the plant specific PRA.

Generic Adjustment Values

Generic values have been developed for monitored components that are subject to common cause failure. The correction factor is used as a multiplier on the [FV/UR] ratio for each component in the common cause group. This method may be used for simplicity and is recommended for components that are less significant contributors to the URI (e.g. [FV/UR] is small). The multipliers are provided in the table below. Single train systems are not included.

Table 3. Generic CCF Adjustment Values

To be updated by 01-01-05

System	Component	**Generic CCF Adjustment Values**				
		1.25	1.50	2.00	3.00	5.00
EAC	EDG	2 EDGs (1/2) or 3 EDGs (2/3)	4 EDGs(1/4) with other diverse sources of power	3 EDGs(1/3)		4 EDGs(1/4) and no diverse sources of power
HPI	MDP Running		With SI and CVC		With only CVC	
	MDP Standby		With SI and CVC		With only SI	
HRS	MDP Standby	2 MDP (1/2)			3 MDP (1/3)	
	TDP	2 TDP and 1 MDP			3 TDP and no MDP	
RHR	MDP Standby		ALL			
SWS	MDP Running				ALL	
	MDP Standby		ALL			
	DDP	ALL				
CCW	MDP Running		ALL			
	MDP Standby			ALL		
ALL	MOV			ALL		
ALL	AOV		ALL			

Note: Success criteria noted in parenthesis

NOTE THIS TABLE WILL BE DEVELOPED FOR ALL PLANTS

The Multiplier in the table above is used to adjust the FV value selected for use in the preceding section. For example, at a plant with three one hundred percent capacity EDG's, the FV selected in the preceding section would be multiplied by 2.00.

Plant Specific Common Cause Adjustment

The general form of a plant specific common cause adjustment factor is given by the equation:

$$A = \frac{\left[\left(\sum_{i=1}^{n} FVi\right) + FVcc\right]}{\sum_{i=1}^{n} FVi}. \qquad \text{Eq. 4}$$

Where:

n = is the number of components in a common cause group,

FV_i = the FV for independent failure of component i,

and

FV_{cc} = the FV for the common cause failure of components in the group.

In the expression above, the FV_i are the values for the specific failure mode for the component group that was chosen because it resulted in the maximum *[FV/UR]* ratio. The FV_{cc} is the FV that corresponds to all combinations of common cause events for that group of components for the same specific failure mode. Note that the FV_{cc} may be a sum of individual FV_{cc} values that represent different combinations of component failures in a common cause group.

For example consider again a plant with three one hundred percent capacity emergency diesel generators. In this example, three failure modes for the EDG are modeled in the PRA, fail to start (FTS), fail to load (FTL) and fail to run (FTR). Common cause events exist for each of the three failure modes of the EDG in the following combinations:

1) Failure of all three EDGs,
2) Failure of EDG-A and EDG-B,
3) Failure of EDG-A and EDG-C,
4) Failure of EDG-B and EDG-C.

This results in a total of 12 common cause events.

Assume the maximum [FV/UR] resulted from the FTS failure mode, then the FV_{cc} used in equation 4 would be the sum of the four common cause FTS events for the combinations listed above.

It is recognized that there is significant variation in the methods used to model common cause. It is common that the 12 individual common cause events described above are combined into a fewer number of events in many PRAs. Correct application of the plant specific method would, in this case, require the decomposition of the combined events and their related FV values into the individual parts. This can be accomplished by application of the following proportionality:

$$FVpart = FVtotal \times \frac{URpart}{URtotal} \qquad \text{Eq. 5}$$

Returning to the example above, assume that common cause was modeled in the PRA by combining all failure modes for each specific combination of equipment modeled. Thus there would be four common cause events corresponding to the four possible equipment groupings listed above, but each of the common cause events would include the three failure modes FTS, FTL and FTR. Again, assume the FTS independent failure mode is the event that resulted in the maximum [FV/UR] ratio. The FVcc value to be used would be determined by determining the FTS contribution for each of the four common cause events. In the case of the event representing failure of all three EDGs this would be determined from

$$FV_{FTSABC} = FV_{ABC} \times \frac{UR_{FTSABC}}{UR_{ABC}}.$$

Where,

FV_{FTSABC} = the FV for the FTS failure mode and the failure of all three EDGs

FV_{ABC} = the event from the PRA representing the failure of all three EDGs due to all failure modes

UR_{FTSABC} = the failure probability for a FTS of all three EDGs, and

UR_{ABC} = the failure probability for all failure modes for the failure of all three EDGs.

After this same calculation was performed for the remaining three common cause events, the value for FV_{CC} to be used in equation 4 would then be calculated from:

$$FV_{cc} = FV_{FTSABC} + FV_{FTSAB} + FV_{FTSAC} + FV_{FTSBC}$$

This value is used in equation 4 to determine the value of A. The final quantity used in equation 3 is given by:

$$[FV/UR]_{\max} = A*[FV/UR]_{ind}$$

In this case the individual values on the right hand side of the equation above are input to CDE.

2.3.3. Birnbaum Importance

One of the rules used for determining the valves to be monitored in this performance indicator permitted the exclusion of valves with a Birnbaum importance less than 1.0e-06. To apply this screening rule the Birnbaum importance is calculated from the values derived in this section as:

$$B = CDF*A*[FV/UR]_{ind} = CDF*[FV/UR]_{max}$$

2.3.4. Calculation of UR_{Bc}

Component unreliability is calculated by:

$$UR_{Bc} = P_D + \lambda T_m. \qquad \text{Eq 6}$$

Where:

P_D is the component failure on demand probability calculated based on data collected during the previous 12 quarters,

λ is the component failure rate (per hour) for failure to run calculated based on data collected during the previous 12 quarters,

and

T_m is the risk-significant mission time for the component based on plant specific PRA model assumptions. Where there is more than one mission time for different initiating events or sequences (e.g., turbine-driven AFW pump for loss of offsite power with recovery versus loss of feedwater), the longest mission time is to be used.

NOTE:

For valves only the P_D term applies

For pumps $P_D + \lambda\, T_m$ applies

For diesels $P_{D\,start} + P_{D\,load\,run} + \lambda\, T_m$ applies

The first term on the right side of equation 6 is calculated as follows.[6]

$$PD = \frac{(Nd + a)}{(a + b + D)}. \qquad \text{Eq. 7}$$

where in this expression:

N_d is the total number of failures on demand during the previous 12 quarters,

D is the total number of demands during the previous 12 quarters determined in section 2.2.1

The values a and b are parameters of the industry prior, derived from industry experience (see Table 4).

In the calculation of equation 5 the numbers of demands and failures is the sum of all demands and failures for similar components within each system. Do not sum across units for a multi-unit plant. For example, for a plant with two trains of Emergency Diesel Generators, the demands and failures for both trains would be added together for one evaluation of P_D which would be used for both trains of EDGs.

In the second term on the right side of equation 6, λ is calculated as follows.

$$\lambda = \frac{(Nr + a)}{(Tr + b)} \qquad \text{Eq. 8}$$

[6] Atwood, Corwin L., Constrained noninformative priors in risk assessment, *Reliability Engineering and System Safety*, 53 (1996; 37-46)

where:

N_r is the total number of failures to run during the previous 12 quarters (determined in section 2.2.2),

T_r is the total number of run hours during the previous 12 quarters (determined in section 2.2.1)

and

a and b are parameters of the industry prior, derived from industry experience (see Table 4).

In the calculation of equation 8 the numbers of demands and run hours is the sum of all run hours and failures for similar components within each system. Do not sum across units for a multi-unit plant. For example, a plant with two trains of Emergency Diesel Generators, the run hours and failures for both trains would be added together for one evaluation of λ which would be used for both trains of EDGs.

2.3.5. Baseline Unreliability Values

The baseline values for unreliability are contained in Table 4 and remain fixed.

Table 4. Industry Priors and Parameters for Unreliability

Component	Failure Mode	a[a]	b[a]	Industry MeanValue[b] URBLC
Circuit Breaker		4.99E-1	6.23E+2	8.00E-4
Motor-operated valve	Fail to open (or close)	4.99E-1	7.12E+2	7.00E-4
Air-operated valve	Fail to open (or close)	4.98E-1	4.98E+2	1.00E-3
Motor-driven pump, standby	Fail to start	4.97E-1	2.61E+2	1.90E-3
	Fail to run	5.00E-1	1.00E+4	5.00E-5
Motor-driven pump, running or alternating	Fail to start	4.98E-1	4.98E+2	1.00E-3
	Fail to run	5.00E-1	1.00E+5	5.00E-6
Turbine-driven pump, AFWS	Fail to start	4.85E-1	5.33E+1	9.00E-3
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Turbine-driven pump,	Fail to start	4.78E-1	3.63E+1	1.30E-2

Component	Failure Mode	a[a]	b[a]	Industry Mean Value[b] URBLC
HPCI or RCIC	Fail to run	5.00E-1	2.50E+3	2.00E-4
Diesel-driven pump, AFWS	Fail to start	4.80E-1	3.95E+1	1.20E-2
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Emergency diesel generator	Fail to start	4.92E-1	9.79E+1	5.00E-3
	Fail to load/run	4.95E-1	1.64E+2	3.00E-3
	Fail to run	5.00E-1	6.25E+2	8.00E-4

NOTE: THIS TABLE IS SUBJECT TO UPDATE PRIOR TO IMPLEMENTATION

a. A constrained, non-informative prior is assumed. For failure to run events, a = 0.5 and b = (a)/(mean rate). For failure upon demand events, a is a function of the mean probability:

Mean Probability	a
0.0 to 0.0025	0.50
>0.0025 to 0.010	0.49
>0.010 to 0.016	0.48
>0.016 to 0.023	0.47
>0.023 to 0.027	0.46

Then b = (a)(1.0 - mean probability)/(mean probability).

b. Failure to run events occurring within the first hour of operation are included within the fail to start failure mode. Failure to run events occurring after the first hour of operation are included within the fail to run failure mode.

c. Fail to load and run for one hour was calculated from the failure to run data in the report indicated. The failure rate for 0.0 to 0.5 hour (3.3E-3/h) multiplied by 0.5 hour, was added to the failure rate for 0.5 to 14 hours (2.3E-4/h) multiplied by 0.5 hour.

3. Establishing Statistical Significance

This performance indicator establishes an acceptable level of performance for the monitored systems that is reflected in the baseline reliability values in Table 4. Plant specific differences from this acceptable performance are interpreted in the context of the risk significance of the difference from the acceptable performance level. It is expected that a system that is performing at an acceptable performance level will see variations in performance over the monitoring period. For example a system may, on average, see three failures in a three year period at the accepted level of reliability. It is expected, due to normal performance variation, that this system will sometimes experience two or four failures in a three year period. It is not appropriate that a system should be placed in a white performance band due to expected variation in measured performance. This problem is most noticeable for risk sensitive systems that have few demands in the three year monitoring period.

This problem is resolved by applying a limit of 5.0e-07 to the magnitude of the most significant failure in a system. This ensures that one failure beyond the expected number of failures alone cannot result in MSPI > 1.0e-06. A MSPI > 1.0e-06 will still be a possible result if there is significant system unavailability, or failures in other components in the system.

This limit on the maximum value of the most significant failure in a system is only applied if the MSPI value calculated without the application of the limit is less than 1.0e-05.

This calculation will be performed by the CDE software, no additional input values are required.

4. Calculation of System Component Performance Limits

The mitigating systems chosen to be monitored are generally the most important systems in nuclear power stations. However, in some cases the system may not be as important at a specific station. This is generally due to specific features at a plant, such as diverse methods of achieving the same function as the monitored system. In these cases a significant degradation in performance could occur before the risk significance reached a point where the MSPI would cross the white boundary. In cases such as this it is not likely that the performance degradation would be limited to that one system and may well involve cross cutting issues that would potentially affect the performance of other mitigating systems.

A performance based criterion for determining degraded performance is used as an additional decision criteria for determining that performance of a mitigating system has degraded to the white band. This decision is based on deviation of system performance from expected performance. The decision criterion was developed such that a system is placed in the white performance band when there is high confidence that system performance has degraded even though MSPI < 1.0e-06.

The criterion is applied to each component type in a system. If the number of failures in a 36 month period for a component type exceeds a performance based limit, then the system is considered to be performing at a white level, regardless of the MSPI calculated value. The performance based limit is calculated in two steps:

1. Determine the expected number of failures for a component type and
2. Calculate the performance limit from this value.

The expected number of failures is calculated from the relation

$$Fe = Nd * p + \lambda * Tr$$

Where:

N_d is the number of demands

p is the probability of failure on demand, from Table 4.

λ is the failure rate, from Table 4.

T_r is the runtime of the component

This value is used in the following expression to determine the maximum number of failures:

$$Fm = 4.65 * Fe + 4.2$$

If the actual number of failures (Fa) of a similar group of components (components that are grouped for the purpose of pooling data) within a system in a 36 month period exceeds Fm, then the system is placed in the ~~largest of the~~ white performance *band*~~level~~ or the level dictated by the MSPI calculation *if the MSPI calculation is > 1E-5.*

This calculation will be performed by the CDE software, no additional input values are required.

5. Additional Guidance for Specific Systems

This guidance provides typical system scopes. Individual plants should include those systems *and components* employed at their plant that are necessary to satisfy ~~the~~ *those* specific ~~risk-significant~~ functions described below *that have been determined to be risk significant per NUMARC 93-01* and reflected in their PRAs.

Emergency AC Power Systems

Scope

The function monitored for the emergency AC power system is the ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power while the reactor is critical, including post-accident conditions. The emergency AC power system is typically comprised of two or more independent emergency generators that provide AC power to class 1E buses following a loss of off-site power. The emergency generator dedicated to providing AC power to the high pressure core spray system in BWRs is not within the scope of emergency AC power.

The electrical circuit breaker(s) that connect(s) an emergency generator to the class lE buses that are normally served by that emergency generator are considered to be part of the emergency generator train.

Emergency generators that are not safety grade, or that serve a backup role only (e.g., an alternate AC power source), are not included in the performance reporting.

Train Determination

The number of emergency AC power system trains for a unit is equal to the number of class 1E emergency generators that are available to power safe-shutdown loads in the event of a loss of off-site power for that unit. There are three typical configurations for EDGs at a multi-unit station:

1. EDGs dedicated to only one unit.
2. One or more EDGs are available to "swing" to either unit

3. All EDGs can supply all units

For configuration 1, the number of trains for a unit is equal to the number of EDGs dedicated to the unit. For configuration 2, the number of trains for a unit is equal to the number of dedicated EDGs for that unit plus the number of "swing" EDGs available to that unit (i.e., The "swing" EDGs are included in the train count for each unit). For configuration 3, the number of trains is equal to the number of EDGs.

Clarifying Notes

The emergency diesel generators are not considered to be available during the following portions of periodic surveillance tests unless recovery from the test configuration during accident conditions is virtually certain, as described in "Credit for operator recovery actions during testing," can be satisfied; or the duration of the condition is less than fifteen minutes per train at one time:

- Load-run testing
- Barring

An EDG is not considered to have failed due to any of the following events:

- spurious operation of a trip that would be bypassed in a loss of offsite power event
- malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources)
- failure to start because a redundant portion of the starting system was intentionally disabled for test purposes, if followed by a successful start with the starting system in its normal alignment

Air compressors are not part of the EDG boundary. However, air receivers that provide starting air for the diesel are included in the EDG boundary.

If an EDG has a dedicated battery independent of the station's normal DC distribution system, the dedicated battery is included in the EDG system boundary.

The fuel transfer pumps are not considered to be a monitored component in the EDG system. They are considered to be a support system.

BWR High Pressure Injection Systems

(High Pressure Coolant Injection, High Pressure Core Spray, and Feedwater Coolant Injection)

Scope

These systems function at high pressure to maintain reactor coolant inventory and to remove decay heat following a small-break Loss of Coolant Accident (LOCA) event or a loss of main feedwater event.

The function monitored for the indicator is the ability of the monitored system to take suction from the suppression pool (and from the condensate storage tank, if credited in the plant's accident analysis) and inject into the reactor vessel.

Plants should monitor either the high-pressure coolant injection (HPCI), ~~the~~ high-pressure core spray (HPCS), or the feedwater coolant injection (FWCI) system, whichever is installed. The turbine and governor ~~(or motor driven FWCI pumps),~~ and associated piping and valves for turbine steam supply and exhaust are within the scope of the *RCICs* systems. *The motor driven pump for HPCS and FWCI are in scope along with any valves ~~that~~ must change state such as low flow valves in FWCI.* Valves in the feedwater line are not considered within the scope of these systems *because they are normally open during operation and do not need to change state for these systems to operate. However waterside valves up to the feedwater line are in scope if they need to change state such as the HPCI injection valve.*

The emergency generator dedicated to providing AC power to the high-pressure core spray system is included in the scope of the HPCS. The HPCS system typically includes a "water leg" pump to prevent water hammer in the HPCS piping to the reactor vessel. The "water leg" pump and valves in the "water leg" pump flow path are ancillary components and are not included in the scope of the HPCS system. Unavailability is not included while critical if the system is below steam pressure specified in technical specifications at which the system can be operated.

Train Determination

The HPCI and HPCS systems are considered single-train systems. The booster pump and other small pumps are ancillary components not used in determining the number of trains. The effect of these pumps on system performance is included in the system indicator to the extent their failure detracts from the ability of the system to perform its risk-significant function. For the FWCI system, the number of trains is determined by the number of feedwater pumps. The number of condensate and feedwater booster pumps are not used to determine the number of trains.

Reactor Core Isolation Cooling

(or Isolation Condenser)

Scope

This system functions at high pressure to remove decay heat following a loss of main feedwater event. The RCIC system also functions to maintain reactor coolant inventory following a very small LOCA event.

The function monitored for the indicator is the ability of the RCIC system to cool the reactor vessel core and provide makeup water by taking a suction from either the condensate storage tank or the suppression pool and injecting at rated pressure and flow into the reactor vessel.

The Reactor Core Isolation Cooling (RCIC) system turbine, governor, and associated piping and valves for steam supply and exhaust are within the scope of the RCIC system. Valves in the feedwater line are not considered within the scope of the RCIC system *because they are normally open during operation and do not have to change state for RCIC to perform its function.*

The Isolation Condenser and inlet valves are within the scope of Isolation Condenser system *along with the connecting active valve for isolation condenser makeup.* Unavailability is not included while critical if the system is below steam pressure specified in technical specifications at which the system can be operated.

Train Determination

The RCIC system is considered a single-train system. The condensate and vacuum pumps are ancillary components not used in determining the number of trains. The effect of these pumps on RCIC performance is included in the system indicator to the extent that a component failure results in an inability of the system to perform its risk-significant function.

For Isolation Condensers, a train is a flow path from the reactor to the isolation condenser back to the reactor. *The ~~makeup~~ valve to the isolation condenser is included in the train.*

Connecting

BWR Residual Heat Removal Systems

Scope

The functions monitored for the BWR residual heat removal (RHR) system are the ability of the RHR system to remove heat from the suppression pool, provide low pressure coolant injection, and provide post-accident decay heat removal. The pumps, heat exchangers, and associated piping and valves for those functions are included in the scope of the RHR system.

Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers.

PWR High Pressure Safety Injection Systems

Scope

These systems are used primarily to maintain reactor coolant inventory at high pressures following a loss of reactor coolant. HPSI system operation following a small-break LOCA involves transferring an initial supply of water from the refueling water storage tank (RWST) to cold leg piping of the reactor coolant system. Once the RWST inventory is depleted, recirculation of water from the reactor building emergency sump is required. The function monitored for HPSI is the ability of a HPSI train to take a suction from the primary water source (typically, a borated water tank), or from the containment emergency sump, and inject into the reactor coolant system at rated flow and pressure.

The scope includes the pumps and associated piping and valves from both the refueling water storage tank and from the containment sump to the pumps, and from the pumps into the reactor coolant system piping. For plants where the high-pressure injection pump takes suction from the residual heat removal pumps, the residual heat removal pump discharge header isolation valve to the HPSI pump suction is included in the scope of HPSI system. Some components may be included in the scope of more than one train. For example, cold-leg injection lines may be fed from a common header that is supplied by both HPSI trains. In these cases, the effects of testing or component failures in an injection line should be reported in both trains.

Train Determination

In general, the number of HPSI system trains is defined by the number of high head injection paths that provide cold-leg and/or hot-leg injection capability, as applicable.

For Babcock and Wilcox (B&W) reactors, the design features centrifugal pumps used for high pressure injection (about 2,500 psig) and no hot-leg injection path. Recirculation from the containment sump requires operation of pumps in the residual heat removal system. They are typically a two-train system, with an installed spare pump (depending on plant-specific design) that can be aligned to either train.

For two-loop Westinghouse plants, the pumps operate at a lower pressure (about 1600 psig) and there may be a hot-leg injection path in addition to a cold-leg injection path (both are included as a part of the train).

For Westinghouse three-loop plants, the design features three centrifugal pumps that operate at high pressure (about 2500 psig), a cold-leg injection path through the BIT (with two trains of redundant valves), an alternate cold-leg injection path, and two hot-leg injection paths. One of the pumps is considered an installed spare. Recirculation is provided by taking suction from the RHR pump discharges. A train consists of a pump, the pump suction valves and boron injection tank (BIT) injection line valves electrically associated with the pump, and the associated hot-leg injection path. The alternate cold-leg injection path is required for recirculation, and should be included in the train with which its isolation valve is electrically associated. This represents a two-train HPSI system.

For Four-loop Westinghouse plants, the design features two centrifugal pumps that operate at high pressure (about 2500 psig), two centrifugal pumps that operate at an intermediate pressure (about 1600 psig), a BIT injection path (with two trains of injection valves), a cold-leg safety injection path, and two hot-leg injection paths. Recirculation is provided by taking suction from the RHR pump discharges. Each of two high pressure trains is comprised of a high pressure centrifugal pump, the pump suction valves and BIT valves that are electrically associated with the pump. Each of two intermediate pressure trains is comprised of the safety injection pump, the suction valves and the hot-leg injection valves electrically associated with the pump. The cold-leg safety injection path can be fed with either safety injection pump, thus it should be associated with both intermediate pressure trains. This HPSI system is considered a four-train system for monitoring purposes.

For Combustion Engineering (CE) plants, the design features two or three centrifugal pumps that operate at intermediate pressure (about 1300 psig) and provide flow to two or four cold-leg injection paths or two hot-leg injection paths. In most designs, the HPSI pumps take suction directly from the containment sump for recirculation. In these cases, the sump suction valves are included within the scope of the HPSI system. This is a two-train system (two trains of combined cold-leg and hot-leg injection capability). One of the three pumps is typically an installed spare that can be aligned to either train or only to one of the trains (depending on plant-specific design).

PWR Auxiliary Feedwater Systems

Scope

The AFW system provides decay heat removal via the steam generators to cool down and depressurize the reactor coolant system following a reactor trip. The AFW system is assumed to be required for an extended period of operation during which the initial supply of water from the condensate storage tank is depleted and water from an alternative water source (e.g., the service water system) is required. Therefore components in the flow paths from both of these water sources are included; however, the alternative water source (e.g., service water system) is not included.

The function monitored for the indicator is the ability of the AFW system to take a suction from the primary water source (typically, the condensate storage tank) or, if required, from an emergency source (typically, a lake or river via the service water system) and inject into at least one steam generator at rated flow and pressure.

The scope of the auxiliary feedwater (AFW) or emergency feedwater (EFW) systems includes the pumps and the components in the flow paths from the condensate storage tank and, if required, the valve(s) that connect the alternative water source to the auxiliary feedwater system. Pumps included in the Technical Specifications are included in the scope of this indicator. Startup feedwater pumps are not included in the scope of this indicator.

Train Determination

The number of trains is determined primarily by the number of parallel pumps. For example, a system with three pumps is defined as a three-train system, whether it feeds two, three, or four injection lines, and regardless of the flow capacity of the pumps. Some components may be included in the scope of more than one train. For example, one set of flow regulating valves and isolation valves in a three-pump, two-steam generator system are included in the motor-driven pump train with which they are electrically associated, but they are also included (along with the redundant set of valves) in the turbine-driven pump train. In these instances, the effects of testing or failure of the valves should be reported in both affected trains. Similarly, when two trains provide flow to a common header, the effect of isolation or flow regulating valve failures in paths connected to the header should be considered in both trains.

PWR Residual Heat Removal System

Scope

The functions monitored for the PWR residual heat removal (RHR) system are those that are required to be available when the reactor is critical. These typically include the low-pressure injection function and the post-accident recirculation mode used to cool and recirculate water from the containment sump following depletion of RWST inventory to provide post-accident decay heat removal. The pumps, heat exchangers, and associated piping and valves for those functions are included in the scope of the RHR system. Containment spray function should be included if it is identified as a risk-significant post accident decay heat removal function. Containment spray systems that only provide containment pressure control are not included.

CE Designed NSSS

CE ECCS designs differ from the description above.. CE designs run all ECCS pumps during the injection phase (Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low Pressure Safety Injection (LPSI)), and on Recirculation Actuation Signal (RAS), the LPSI pumps are automatically shutdown, and the suction of the HPSI and CS pumps is shifted to the containment sump. The HPSI pumps then provide the recirculation phase core injection, and the CS pumps by drawing inventory out of the sump, cooling it in heat exchangers, and spraying the cooled water into containment, support the core injection inventory cooling.

For the RHR function the CE plant design uses HPSI to take a suction from the sump, CS to cool the fluid, and HPSI to inject at low pressure into the RCS. Due to these design differences, CE plants with this design should monitor this function in the following manner. The HPSI pumps and their suction valves are already monitored under the HPSI function, and no monitoring under the RHR PI is necessary or required. The two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling. Therefore, for the CE designed plants two trains should be monitored, as follows:

- Train 1 (recirculation mode) Consisting of the "A" containment spray pump, the required spray pump heat exchanger and associated flow path valves.
- Train 2 (recirculation mode) Consisting of the "B" containment spray pump, the required spray pump heat exchanger and associated flow path valves.

Surry, North Anna and Beaver Valley Unit 1

The at power RHR function, is provided by two 100% low head safety injection pumps taking suction from the containment sump and injecting to the RCS at low pressure and with the heat exchanger function (containment sump water cooling) provided by four 50% containment recirculation spray system pumps and heat exchangers.

The RHR Performance Indicator should be calculated as follows. The low head safety injection and recirculation spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling, function as follows:

- "A" train consisting of the "A" LHSI pump, associated MOVS and the required "A" train recirculation spray pumps heat exchangers, and MOVS.
- "B" train consisting of the "B" LHSI pump, associated MOVS and the required "B" train recirculation spray pumps, heat exchangers, and MOVS

Beaver Valley Unit 2

The at power RHR function, is provided by two 100% containment recirculation spray pumps taking suction from the containment sump, and injecting to the RCS at low pressure. The heat exchanger function is provided by two 100% capacity containment recirculation spray system heat exchangers, one per train. The RHR Performance Indicator should be calculated as follows. The two containment recirculation spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling.

Two trains should be monitored as follows:

- Train 1 (recirculation mode) Consisting of the containment recirculation spray pump associated MOVS and the required recirculation spray pump heat exchanger and MOVS.
- Train 2 (recirculation mode) Consisting of containment recirculation spray pump associated MOVS and the required recirculation spray pump heat exchanger, and MOVS.

.Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers. Some components are used to provide more than one function of RHR. If a component cannot perform as designed, rendering its associated train incapable of meeting one of the risk-significant functions, then the train is considered to be failed. Unavailable hours would be reported as a result of the component failure.

Cooling Water Support System

Scope

The function of the cooling water support system is to provide for direct cooling of the components in the other monitored systems. It does not include indirect cooling provided by room coolers or other HVAC features.

Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to the other monitored systems are included in the system scope up to, but not including, the last valve that connects the cooling water support system to a single component in another monitored system. This last valve is included in the other monitored system boundary. Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

Valves in the cooling water support system that must close to ensure sufficient cooling to the other monitored system components to meet risk significant functions are included in the system boundary.

If a cooling water system provides cooling to only one monitored system, then it should be included in the scope of that monitored system.

Train Determination

The number of trains in the Cooling Water Support System will vary considerably from plant to plant. The way these functions are modeled in the plant-specific PRA will determine a logical approach for train determination. For example, if the PRA modeled separate pump and line segments, then the number of pumps and line segments would be the number of trains.

Clarifying Notes

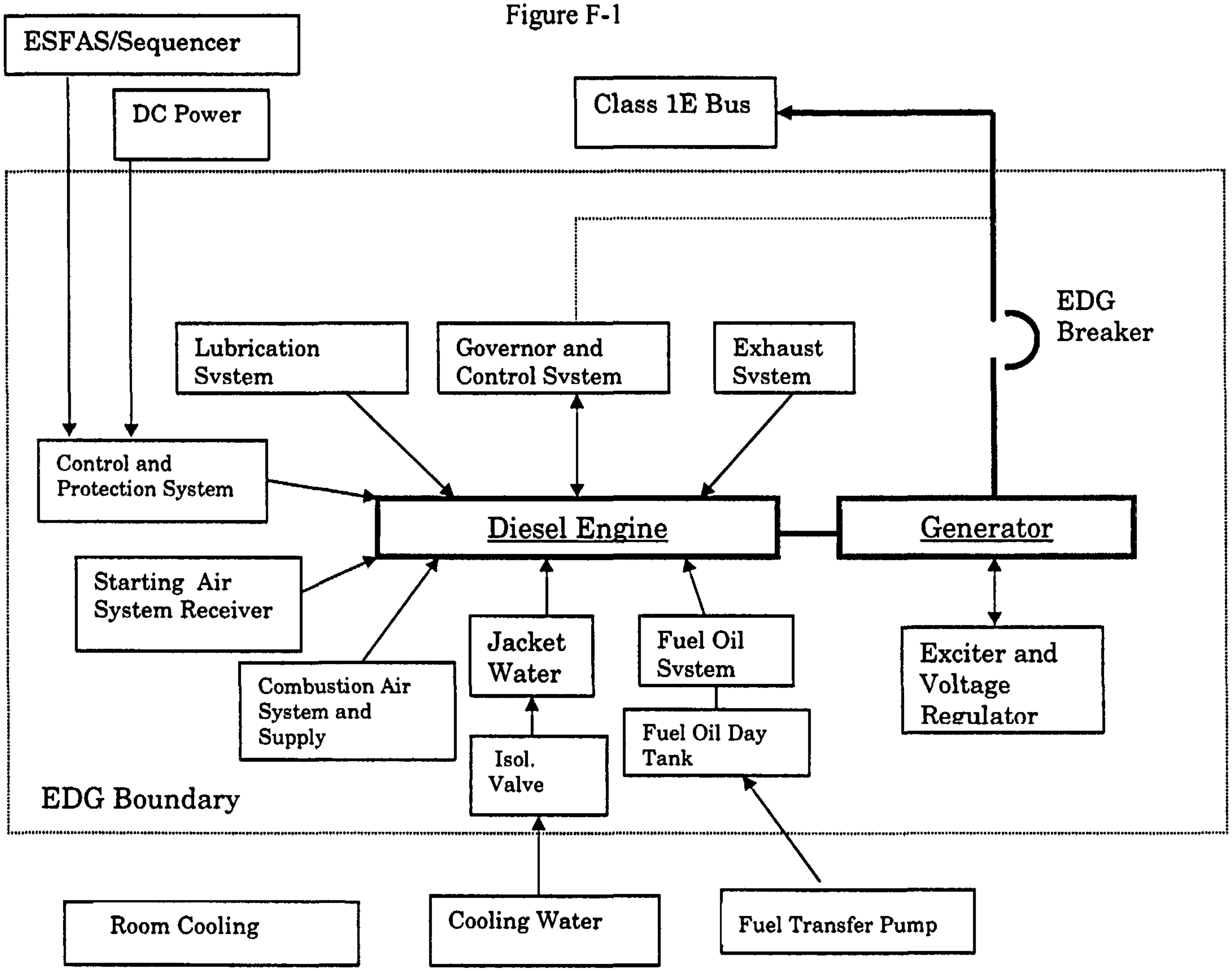
Service water pump strainers, *cyclone separators, and* traveling screens are not considered to be monitored components and are therefore not part of URI. However, clogging of strainers and screens that render the train unavailable to perform its risk significant cooling function (which includes the risk-significant mission times) are included in UAI.

.

1

2

Figure F-1



3

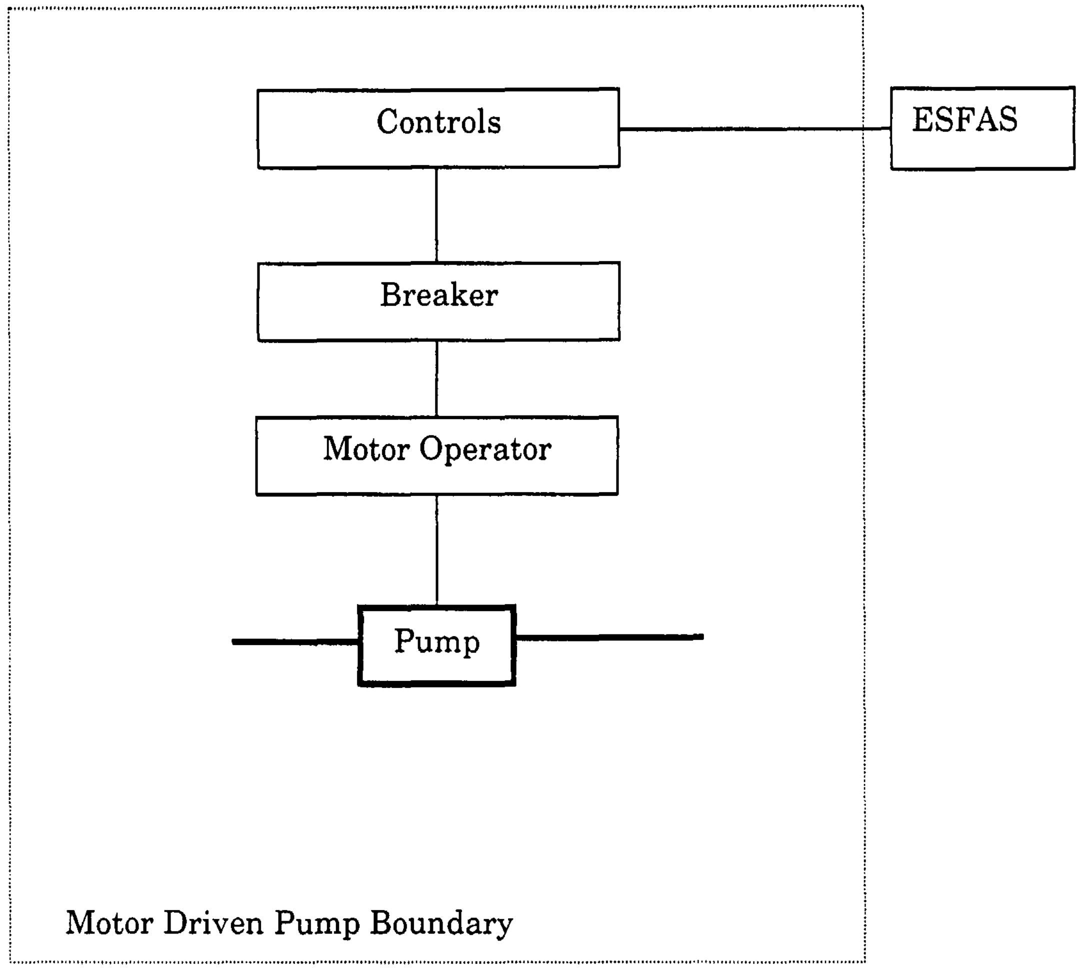

Controls
ESFAS
Breaker
Motor Operator
Pump
Motor Driven Pump Boundary

Figure F-2

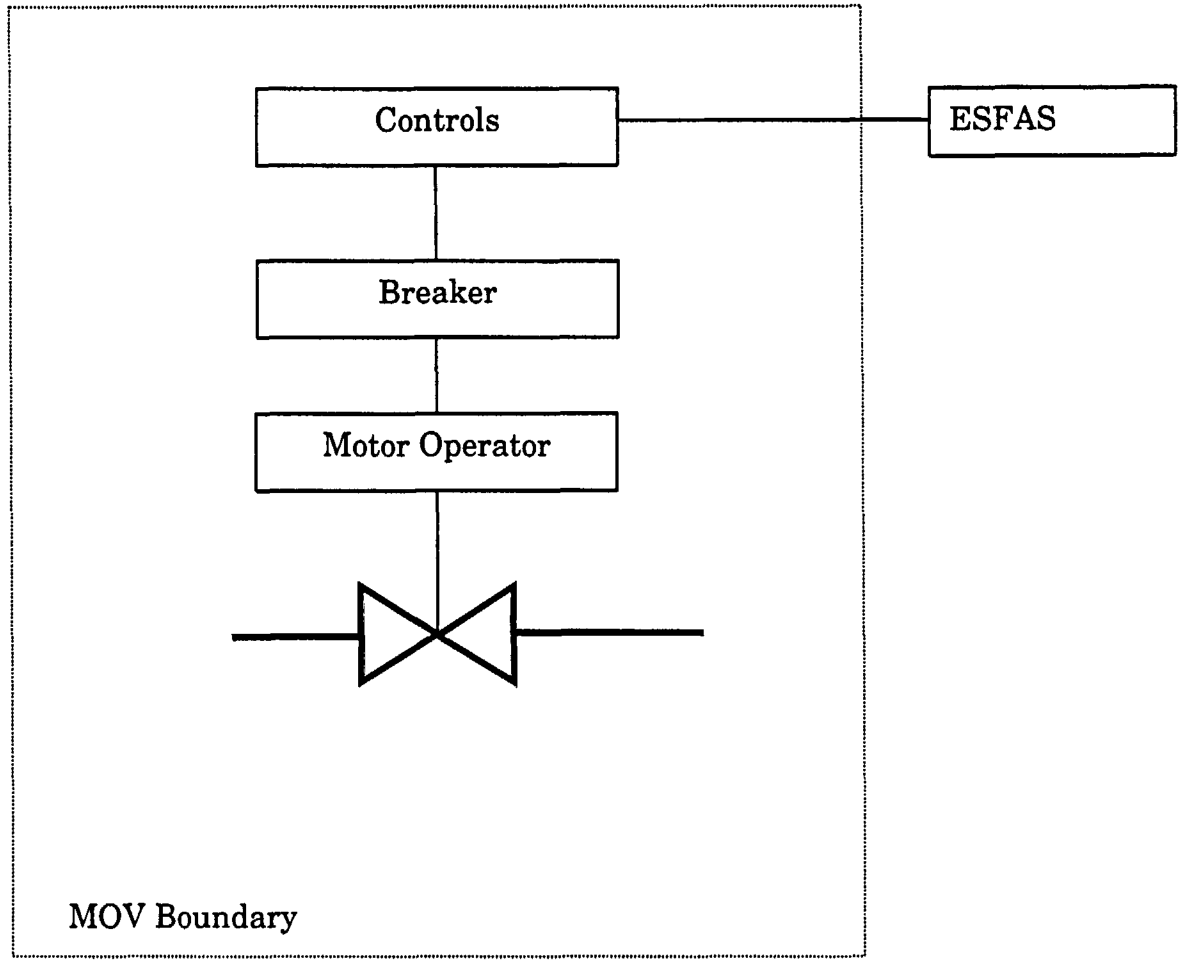


Figure F-3

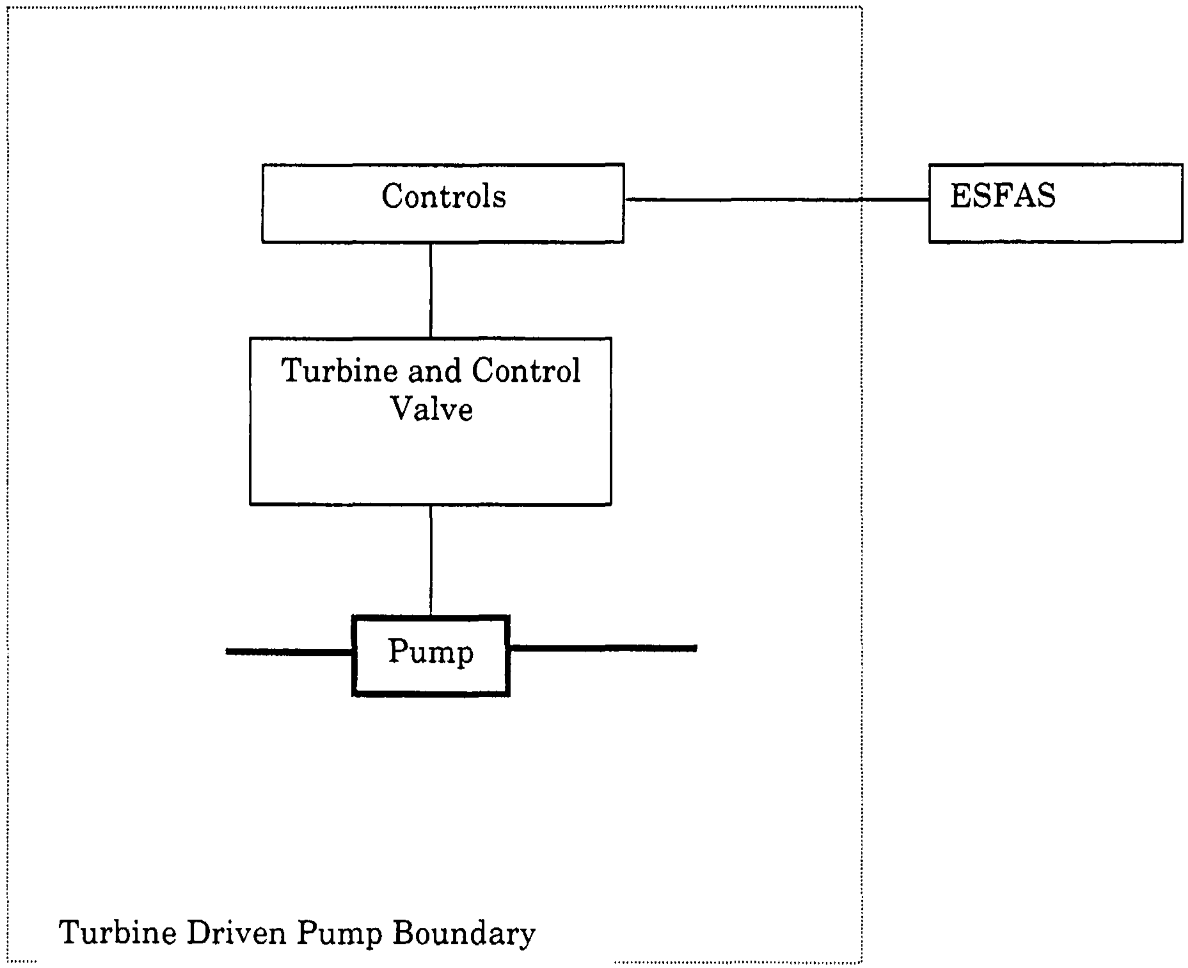

Controls
ESFAS
Turbine and Control Valve
Pump
Turbine Driven Pump Boundary

Figure F-4

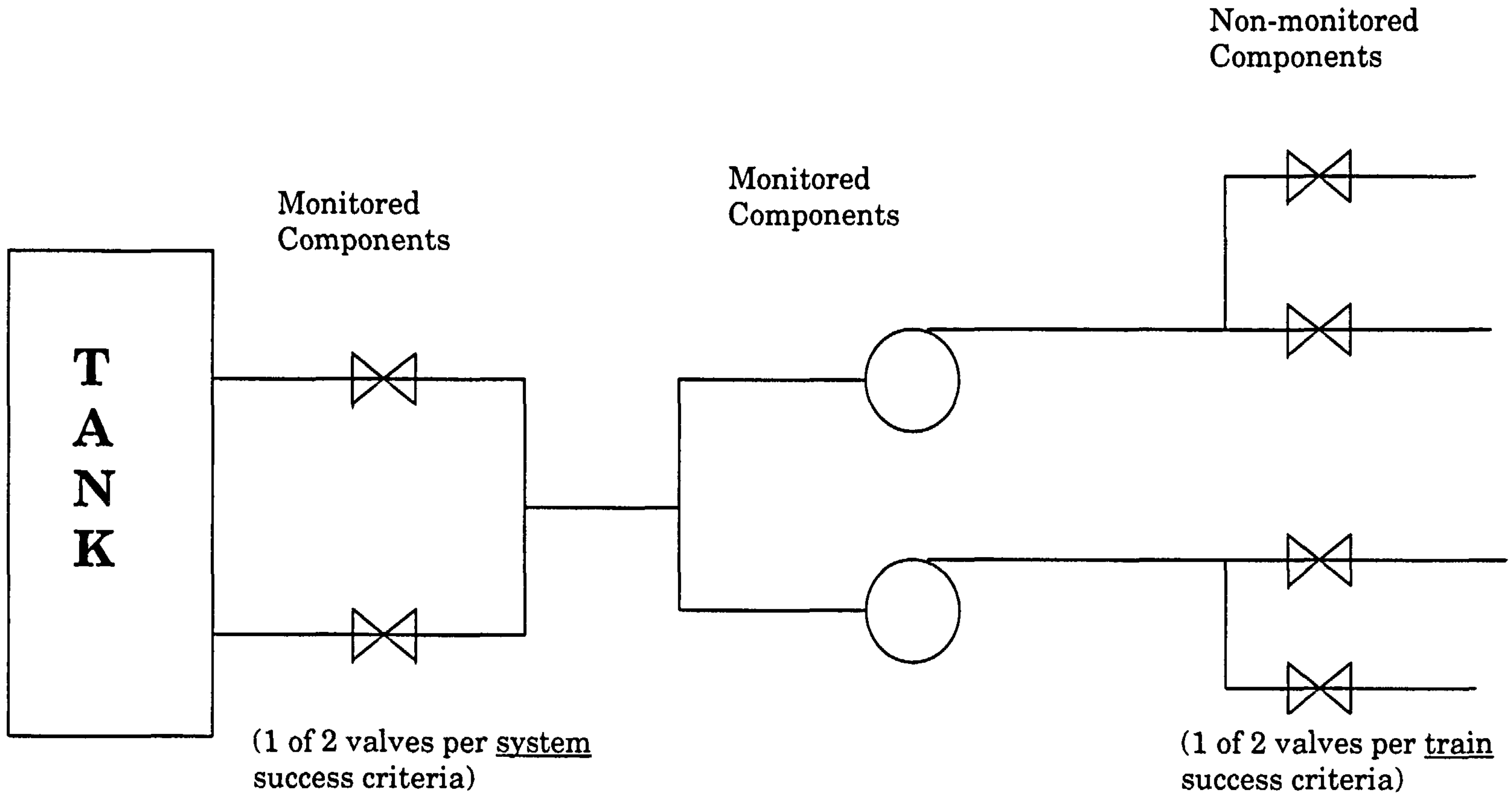

Non-monitored
Components
Monitored
Components
Monitored
Components
TANK
(1 of 2 valves per system
success criteria)
(1 of 2 valves per train
success criteria)

Figure F-5

NEI 99-02 Appendix G, MSPI Basis Document Development

To implement the Mitigating Systems Performance Index (MSPI), Licensees will develop a plant specific basis document that documents the information and assumptions used to calculate the Reactor Oversight Program (ROP) MSPI. This basis document is necessary to support the NRC inspection process, and to record the assumptions and data used in developing the MSPI on each site.

The Basis document will have two major sections. The first described below will document the information used in developing the MSPI. The second section will document the conformance of the plant specific PRA to the requirements that are outlined in this appendix.

I. MSPI Data

The basis document provides a separate section for each monitored system as defined in Section 2.2 of NEI 99-02. The section for each monitored system contains the following subsections:

A. System Boundaries

This section contains a description of the boundaries for each train of the monitored system. A plant drawing or figure (training type figure) should be included and marked adequately (i.e., highlighted trains) to show the boundaries. The guidance for determining the boundaries is provided in Appendix F, Section 1.1 of NEI 99-02.

B. Risk Significant Functions

This section lists the risk significant functions for each train of the monitored system. Risk Significant Functions are defined in section 2.2 of NEI 99-02. Additional detail is given in Appendix F, Section 2.1.1 and Section 5 "Additional Guidance for Specific Systems". A single list for the system may be used as long as any differences between trains are clearly identified. This section may also be combined with the section on Success Criteria if a combination of information into a table format is desired.

C. Success Criteria

This section documents the success criteria as defined in Section 2.2 of NEI 99-02 for each of the identified risk significant functions identified for the system. Additional detail is given in Appendix F, Section 2.1.1. The criteria used should be the documented PRA success criteria. *If the licensee has chosen to use design basis success criteria in the PRA, it is not required to separately document them other than to indicate that is what was used.*~~Otherwise plant design basis values are used, and identified in this section~~. Where there are different success criteria for different functions or initiators, all should be recorded and the most restrictive shown as the one used.

D. Mission Time

This section documents the risk significant mission time as defined in Section 2.2 of NEI 99-02 for each of the identified risk significant functions identified for the system. The default value of 24 hours should be used unless other values are used in the plant PRA, documented by the plant, and identified in this section.

E. Monitored Components

This section documents the selection of monitored components as defined in Appendix F, Section 2.1.2 of NEI 99-02 in each train of the monitored system. A listing of all monitored pumps, breakers and EDG's should be included in this section. A listing of AOV's and MOV's that change state to achieve the risk significant functions should be provided as potential monitored components. The basis for excluding valves in this list from monitoring should be provided. Component boundaries as described in Appendix F, Section 2.1.3 of NEI 99-02 should be included where appropriate.

F. Basis for Demands/Run Hours (estimate or actual)

The determination of reliability largely relies on the values of demands, run hours and failures of components to develop a failure rate. This section documents how the licensee will determine the demands on a component. Several methods may be used.

- Actual counting of demands/run hours during the reporting period
- An estimate of demands/run hours based on the number of times a procedure or other activities is performed *plus actual ESF demands/run hours*
- An estimate based on historical data over a year or more averaged for a quarterly average *plus actual ESF demands/run hours*

The method used is described and the basis information documented.

G. Short Duration Unavailability

This section provides a list of any periodic surveillances or evolutions of less than 15 minutes of unavailability that the licensee does not include in train unavailability. The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact.

~~***Credit for Operator Recovery Actions to Restore the Risk-Significant Functions***~~

~~*This section provides a list of test or maintenance activities that have been evaluated and meet the criteria for allowing credit for operator action to restore the risk significant function. Systems will not be considered unavailable during the performance of these activities.*~~

H. PRA Information used in the MSPI

1. Unavailability FV and UA

This section includes a table or spreadsheet that lists the basic events for unavailability for each train of the monitored systems. This listing should include the probability, FV, and FV/probability ratio and text description of the basic event or component ID. *An example format is provided as Table 1 at the end of this appendix.*

a) Unavailability Baseline Data

This section includes the baseline unavailability data by train for each monitored system. The discussion should include the basis for the baseline values used. *The detailed basis for the baseline data may be included in an appendix to the MSPI Basis Document if desired.*

b) Treatment of Support System Initiator(s)

This section documents whether the cooling water systems are an initiator or not. This section provides a description of how the plant will include the support system initiator(s) as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section. A sample table format for presenting the results of a plant specific calculation for those plants that do not explicitly model the effect on the initiating event contribution to risk is shown in Table 3 at the end of this appendix.

2. Unreliability FV and UR

This section includes a table or spreadsheet that lists the basic events for component failures for each monitored component. This listing should include the probability, FV, the common cause adjustment factor and FV/probability ratio and text description of the basic event or component ID. *An example format is provided as Table 2 at the end of this appendix.*

a) Treatment of Support System Initiator*(s)*

This section documents whether the cooling water systems are an initiator or not. This section provides a description of how the plant will include the support system initiator*(s)* as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section. *A sample table format for presenting the results of a plant specific calculation for those plants that do not explicitly model the effect on the initiating event contribution to risk is shown in Table 3 at the end of this appendix.*

b) Calculation of Common Cause Factor

This section contains the description of how the plant will determine the common cause factor as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section.

~~*H.*~~*I.* Assumptions

This section documents any specific assumptions made in determination of the MSPI information that may need to be documented. Causes for documentation in this section could be special methods of counting hours or runtimes based on plant specific designs or processes, or other instances not clearly covered by the guidance in NEI 99-02.

II. PRA REQUIREMENTS

A. *INSERT THE PRA TECHNICAL ADEQUACY REQUIREMENTS DEVELOPED BY THE EXPERT PANEL HERE*

B. *DOCUMENT HOW THE PLANT PRA MEETS THE PRA TECHNICAL ADEQUACY REQUIREMENTS HERE*

III. *EXAMPLE TABLES*

Table 1 Unavailability Data HPSI (one table per system)

Train	*Basic Event Name*	*Basic Event Description*	*Basic Event Probability (UA)*	*Basic Event FV*	*FV/UA*
A	*1SIAP02----MP6CM*	*HPSI Pump A Unavailable Due to Mntc*	*3.20E-03*	*3.19E-03*	*9.97E-01*
B	*1SIBP02----MP6CM*	*HPSI Pump B Unavailable Due to Mntc*	*3.20E-03*	*3.85E-03*	*1.20E+00*

Table 2 Unreliability Data (one table per monitored component)

Component Name and ID: *HPSI Pump B - 1SIBP02*

Basic Event Name	*Basic Event Description*	*Basic Event Probability (UR)*	*Basic Event FV*	*[FV/UR]ind*	*Common Cause Adjustment Factor (A)*	*Common Cause Adjustment Generic or Plant Specific*	*(FV/UR)*A*
1SIBP02---XCYXOR	*HPSI Pump B Fails to Start Due to Override Contact Failure*	***6.81E-04***	***7.71E-04***	*1.13E+00*	***3.0***	*Generic*	*3.39*
1SIBP02----MPAFS	*HPSI Pump B Fails to Start (Local Fault)*	*6.73E-04*	*7.62E-04*	*1.13E+00*			
1SIBP02----MP-FR	*HPSI Pump B Fails to Run*	*4.80E-04*	*5.33E-04*	*1.11E+00*			
1SABHP-K125RXAFT	*HPSI Pump B Fails to Start Due to K125 Failure*	*3.27E-04*	*3.56E-04*	*1.09E+00*			
1SIBP02----CB0CM	*HPSI Pump B Circuit Breaker (PBB-S04E) Unavailable Due to Mntc*	*2.20E-04*	*2.32E-04*	*1.05E+00*			
1SIBP02----CBBFT	*HPSI Pump B Circuit Breaker (PBB-S04E) Fails to Close (Local Fault)*	*2.04E-04*	*2.14E-04*	*1.05E+00*			

Table 3 Cooling Water Support System FV Calculation Results

FVa (or FVc)	*FVie*	*FVsa (orFVsc)*	*UA (or UR)*	*Calculated FV (per appendix F) (result is put in column 5 of table 1 or table 2 as appropriate)*

TempNo.	PI	Question/Response	Status	Plant/ Co.
27.3	IE02	Question: Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal Background Information: On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level. The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR." The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required). Verify the following: TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum No TDRFP trip signals are present Depress TDRFP Turbine RESET pushbutton and observe the following Turbine RESET light Illuminates TDRFP High Pressure and Low Pressure Stop Valves OPEN PUSH M/A increase pushbutton on the Manual/Automatic Controller station Should this be considered a scram with the loss of normal heat removal? Proposed Answer: The ROP working group is currently working to prepare a response.	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed	LaSalle
28.3	IE02	Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated. Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events. As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

TempNo.	PI	Question/Response	Status	Plant/ Co.
		(MFP)) until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation. Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal. Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal? Response: The ROP working group is currently working to prepare a response.		
30.8	IE02	Question: Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal? Response: The ROP working group is currently working to prepare a response.	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
32.3a	IE02	Question: An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

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		supply. When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip. It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue. The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs prior to recommencing the startup. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?		
		Response: Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves. During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.		
34.6	IE02	Question:	3/20 Introduced	STP

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		Should the following event be counted as a scram with loss of normal heat removal? STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the main turbine. Approximately 17 minutes after the Unit was manually tripped main condenser vacuum was broken at the discretion of the Shift Supervisor to assist in slowing the turbine. Plant conditions were stabilized using Auxiliary Feedwater and Steam Generator Power Operated Relief Valves. Main Feedwater remained available via the electric motor driven Startup Feedwater pump. Main steam headers remained available to provide cooling via the steam dump valves. At any time vacuum could have been reestablished without diagnoses or repair using established operating procedures until after completion of the scram response procedures. Scrams with a Loss of Normal Heat Removal performance indicator is defined as *"The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems."* This indicator states that a loss of normal heat removal has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of the main steam isolation valves or loss of turbine bypass capability. The determining factor for this indicator is whether or not the normal heat removal path is available, not whether the operators choose to use that path or some other path. The STP plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps are then designed to start on low steam generator levels. This is expected following normal operation above low power levels and in turn provides the normal heat removal. This design functioned as expected on December 15, 2002 when the reactor was manually tripped due to high turbine vibration. Normal plant operating procedures 0POP03-ZG-0006 (Plant Shutdown from 100% to Hot Standby) and 0POP03-ZG-0001 (Plant Heatup) state if Auxiliary Feedwater is being used to feed the steam generators than the preferred method of steaming is through the steam generator power operated relief valves. This can be found in steps 7.4 and 7.5 of 0POP03-ZG-0001 and steps 6.6.5 and 6.6.10 of 0POP03-ZG-0006. The note prior to 6.6.10 states *"the preferred method for controlling SG steaming rates while feeding with AFW is with the SG PORVs"*. The normal heat removal path as defined in NEI 99-02 Revision 2 was in service and functioning properly for seventeen minutes after the manual reactor trip and would have continued to function had not the shift supervisor voluntarily broke condenser vacuum and closed the MSIV's. Interviews with the shift supervisor showed that the decision to break vacuum was two part. 1) Based on experience and reports from the field it was known that vacuum would need to be broken to support the maintenance state required for the main turbine and at a minimum to support timely inspection. 2)This would assist in slowing the turbine. The decision to break vacuum was not based solely on mitigating an off-normal condition or for the safety of personnel or equipment. Because Auxiliary Feedwater system had actuated and was in service as expected, the decision was made to use Auxiliary Feedwater and steam through the SG PORVs. As stated earlier, this is the preferred method of heat removal if the decision to use Auxiliary Feedwater is employed as supported by the normal operating procedures while the plant is in Mode 3. Main feedwater remained available via the electric motor driven Startup Feedwater pump and the main steam headers remained available to provide cooling via the steam dump valves if required. Discussion with the shift supervisor showed he was confident that at any time vacuum could have been readily recovered from the control room without the need for diagnoses or repair using established operating procedures if the need arose. An outside action would be required in drawing vacuum in that a Condenser Air Removal pump would require starting locally in the TGB. This is a simplistic, proceduralized and commonly performed evolution. Personnel are fully confident this would have been performed without incident if required. Closing the MSIVs and breaking vacuum as quickly as possible is not uncommon at STP. For a normal planned shutdown MSIVs are closed and vacuum broken within four to six hours typically to support required maintenance in the secondary. If maintenance in the secondary is known to be critical path than vacuum has been broken as early as three hours and fifteen minutes following opening of the main generator breaker. The only reason that vacuum is not	3/20 Discussed 6/18 Discussed; Question to be revised to reflect discussion 7/24 Discussed	

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		broken sooner is because in most cases it is needed to support chemistry testing. By limiting the flow path as described in NEI 99-02 for normal heat removal there is undue burden being placed on the utility. Only recognizing this one specific flow path reduces operational flexibility and penalizes utilities for imparting conservative decision making. Conditions are established immediately following a reactor trip (100% to Mode 3) that can be sustained indefinitely using Auxiliary Feedwater and steaming through the steam generator PORVs. This fact is again supported in the stations Plant Shutdown from 100% to Hot standby and Plant Heatup normal operating procedures. The cause of a trip, the intended forced outage work scope, or outage duration varies and inevitably will factor into which method of normal long term heat removal is best for the station to employ shortly following a trip. Response: The ROP working group is currently working to prepare a response. Licensee Proposed Response: NO. Since vacuum was secured at the discretion of the Shift Supervisor and could have been restored using existing normally performed operating procedures, the function meets the intention of being available but not used.		
36.1	IE02	Question: With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIV's to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam). At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig. Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low. Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser. As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump. The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event. Does this scram constitute a scram with a loss of normal heat removal? Response:	9/25 Introduced and discussed	Quad Cities

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		No. The normal heat removal path was not lost even though the MSIVs were manually closed to control cooldown rate. There was no leak downstream of the MSIVs, and reopening the MSIVs would not have introduced further complications to the event. The normal heat removal path was purposefully and temporarily isolated to address the cooldown rate, only. Reopening the normal heat removal path was always available at the discretion of the control room operator and would not have involved any diagnosis or repair. Further supporting information: The clarifying notes for this indicator state: "*Loss of normal heat removal path* means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path." In this case, the operator did not choose to use the path through the MSIVs, even though the normal heat removal path was available. The clarifying notes for this indicator also state: "*Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair." In this case, the closing of the MSIVs was performed solely to control reactor cooldown rate. It was not performed to isolate a steam leak. There was no diagnosis or repair involved in this event. The MSIVs could have been reopened following normal plant procedures		
36.2	IE02	Question: Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation? <u>Description of Event:</u> At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours. At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel High Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV).Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored. At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including: stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps. **Problem Assessment:** It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing	9/25 Introduced and discussed	Peach Bottom

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		General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs. Reopening of the MSIVs was: • easily facilitated by restarting Reactor Building ventilation, • completed from the control room using normal operating procedures • without the need of diagnosis or repair Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. <u>Discussion of specific aspects of the event:</u> Was the recognition of the condition from the Control Room? ▪ Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room. Does it require diagnosis or was it an alarm? ▪ The event is annunciated in the control room as described previously. Is it a design issue? ▪ Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3. Are actions virtually certain to be successful? ▪ The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required. Are operator actions proceduralized? ▪ The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room. How does Training address operator actions? ▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training. Are stressful or chaotic conditions during or following an accident expected to be present? • As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions		
		Response: The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.		

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36.8	IE02	Question: On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?" Response: No. Under clarifying notes, page 16, lines 18 - 22, NEI 99-02 states: "Actions or design features to control the reactor cool down rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported." In this case, a feedwater isolation signal had automatically closed the main feed regulating valves, effectively mitigating the high level condition. Manually closing the MSIVs was a conservative procedure driven action, which in this case was not by itself necessary to protect personnel or equipment. The main feed regulating valves were capable of being easily opened from the control room, and the MSIVs were capable of being opened from the control room (after local action to bypass and equalize pressure, see FAQ 303). In addition, the cause of the high steam generator level was due to voltage fluctuations on the offsite power grid which resulted in the operators closing the MSIVs. Clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow , condenser vacuum, or turbine bypass capability caused by loss of offsite power. In this case, offsite power was not lost. However, the disturbances in grid voltage affected the ADFCS system which started a chain of events which ultimately resulted in the closure of the MSIVs.	1/22 Introduced 3/25 Discussed 6/16 Discussed	Ginna
36.9	IE02	Question: During startup activities following a refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations increased as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators. Based on industry operating experience, operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage	1/22 Introduced 3/25 Discussed. Question to be rewritten and response provided 4/22 Question and response provided 6/16 Discussed 7/22 Discussed 8/18 Discussed	Millstone 2

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		Licensed Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34) for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience. Does this SCRAM count against the performance indicator for scrams with loss of normal heat removal?		
		Response: No, this scram does not count against the performance indicator for scrams with loss of normal heat removal. The conditions that resulted in the closure of the MSIVs after the reactor trip were expected for the main turbine startup following rotor replacement. Operator actions for this situation had been incorporated into normal plant procedures.		
38.2	MS01, MS04	Question: If the emergency AC power system or the residual heat removal system is not required to be available for service (e.g., the plant is in "no mode" or Technical Specifications do not require the system to be operable), is it appropriate to include this time in the "hours train required" portion of the safety system performance indicator calculation? NEI 99-02, Revision 2, starting on line 25 of page 33, discusses the term "hours train required" as used in safety system unavailability performance indicators. For the emergency AC power system and residual heat removal system, the guidance allows the "hours train required" to be estimated by the number of hours in the reporting period because the emergency generators are normally expected to be available for service during both plant operations and shutdown, and because the residual heat removal system is required to be available for decay heat removal at all times. ~~The response to FAQ 183 states: "During periods and conditions where Technical Specifications allow both shutdown cooling trains to be removed from service the shutdown cooling system is, in effect, not required and required hours and unavailable hours would not be counted."~~	5/27 Introduced 7/22 Discussed 8/18 Discussed 9/16 Discussed 10/13 Tentative Approval	
		Response: NEI 99-02 permits the hours train required to be estimated by the number of hours in reporting period. It incorrectly states that the residual heat removal system is required to be available for decay heat removal "at all times." NEI 99-02 will be corrected in Rev. 3 to state that it is normally required to be in service at all times. The amount of time emergency AC power systems and residual heat removal systems are not required to be available is typically very small (small portions of outages) and would have minimal impact on the PI result. For example, to increase the RHR result from 1.5% (the threshold) to 1.6% would require 68 days in no mode condition. To increase the EAC result from 2.5% (the threshold) to 2.6% would require 42 days. There is no reason to increase reporting and inspection burden for such a minimal effect.		
38.3	MS01	Appendix D FAQ: Mitigating Systems – Safety System Unavailability, Emergency AC Power During a monthly surveillance test of Emergency Diesel Generator 3 (EDG3), an alarm was received in the control room for an abnormal condition. The jacket water cooling supply to EDG3 had experienced a small leak (i.e., less than 1 gpm) at a coupling connection that resulted in a low level condition and subsequent control room alarm. The Low Jacket Water Pressure Alarm, which annunciates locally and in the control room, indicated low pump suction pressure. This was due to low level in the diesel generator jacket water expansion tank. An Auxiliary Operator (AO) stationed at EDG3 responded to the alarm by opening the manual supply valve to provide makeup water to the expansion tank. EDG3 continued to function normally and the surveillance test was completed satisfactorily. Review of data determined that improper tightening of the coupling was performed after the monthly EDG run on December 8, which led to an unacceptable leak if the EDG was required to run. The coupling was properly repaired and tested,	6/16 Introduced 7/22 Discussed 8/18 Discussed 10/13 Tentative Approval. Response to be rewritten	Brunswick

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		and declared to be available and operable on January 6. The condition existed for approximately 28 days. Although the recovery action was conducted outside of the main control room, it was a simple evolution directed by a procedure step, with a high probability of success. This operator response is similar to the response described in Appendix D FAQ 301. In addition, this operator action would be successful during a postulated loss of offsite power event, except for a 23 hour period when the demineralized water supply level was too low to support gravity feed. The engineering analysis determined that a level of 21' 5" of demineralized water supply level was necessary to support gravity feed to the expansion tank. Another 9" (4,740 gallons) was added to this level to allow for the leak and nominal usage and makeup over the 24 hour mission time. Using this analysis, any time the demineralized water level fell below 22" 2", the EDG was considered to be unavailable. A human reliability analysis calculated the probability of an AO failing to add water to the expansion tank from receipt of the low pressure alarm to be 4.7 E-3. In other words, there would be a greater than 99.5% probability of successful task completion within twenty minutes of receiving the annunciator. Vendor analysis determined that, with the existing leak rate, the EDG would remain undamaged for twenty minutes. The human reliability analysis considered that the low jacket water pressure would be annunciated in the control room, the annunciator procedure provided specific direction for filling the expansion tank, the action is reinforced through operator training, and sufficient time would be available to perform the simple action. In its calculation of the probability of operator recovery, the analysis also considered that another indicator, a low-level expansion tank alarm was out-of-service during this time period. However, although the low expansion tank alarm was out of service, it results in low pump suction pressure which did annunciate. NEI 99-02 Appendix D lists several issues that may be addressed for exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems. 1. The capability to recognize the need for compensatory actions – Low pump suction pressure annunciates in the control room. 2. The availability of trained personnel to perform the compensatory action – This is an uncomplicated action, but operators are trained on it. An auxiliary operator simply has to open one manual valve as directed by the annunciator procedure. 3. The means of communications between the control room and the local operator – Communications can be accomplished either via the plant PA system or a portable radio. 4. The availability of compensatory equipment – No compensatory equipment is necessary. 5. The availability of a procedure for compensatory actions – There is an annunciator procedure in the diesel generator room that would direct the auxiliary operator to open the manual valve. 6. The frequency with which the compensatory actions are performed – This action is performed infrequently, but it was demonstrated to be successful during the surveillance test. 7. The probability of successful completion of compensatory actions within the required time – The human reliability analysis determined that there was a 99.5% probability of successful completion of compensatory action within the required time. In summary, over a 28-day period, jacket water cooling for EDG3 was degraded, but functional for approximately 27 days, and was totally unavailable for 23 hours. This is based on a review of Operator logs, plant trending computer points, and flow calculations. During the 27-day degraded period, a simple manual action directed by procedure and performed by an operator would have been used to ensure that jacket water was available. Should fault exposure hours be reported for the 27 days when the Emergency Diesel Generator 3 jacket water was considered to be degraded but functional?		

<table>
<tr><th>TempNo.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td></td><td></td><td>Response:
Yes, in this case fault exposure hours should be reported</td><td></td><td></td></tr>
<tr><td>38.9</td><td>OR01</td><td>Question:
On March 4, 2004, workers initiated a series of diving activities related to the inspection and repair of the Steam Dryer in the Dryer Separator Pit. On March 5, 2004, a contract diver proceeded to the Unit 1 Reactor Building 117' Elevation in preparation for the next diving evolution on the Steam Dryer. Based on underwater dose gradients from the steam dryer, 5 Electronic Dosimeters (EDs), 10 thermoluminescent dosimeters (TLDs) and a telemetry transmitter were placed on the diver by a Radiation Protection Technician (RPT) to monitor personnel exposure. ED/TLD combinations were placed on the chest, right arm, left arm, right leg, and left leg. TLDs were use to monitor the extremities. Communication between the EDs and the telemetry system was verified after placement on the diver. The RPT conducted the pre-dive radiological briefing and the diver entered the Contaminated Area.
Telemetry problems were experienced prior to the diver entering the Dryer Separator Pit. The underwater antenna was changed out and telemetry problems appeared to be corrected. The diver was in the Dryer Separator Pit approximately 40 minutes when additional telemetry problems occurred. The diver was instructed to exit the water and the transmitter replaced. The telemetry problems were corrected and the diver re-entered the Dryer Separator Pit. After entering the water, the left arm ED stopped communicating with the telemetry system. The telemetry computer was rebooted while the diver was in the Dryer Separator Pit, but the left arm ED failed to transmit. The RP Supervisor evaluated the situation and decided to allow the dive to continue since four of the five EDs were transmitting properly. The left arm ED did not transmit for the remainder of the dive. However, it did remain functional and continued to accumulate dose. Upon completion of the work, the diver exited the Dryer Separator Pit and it was discovered that his left arm ED was in alarm. Specific ED results for the diver are given below:
<table>
<tr><th>ED Location</th><th>ED Result (mrem)</th></tr>
<tr><td>Chest</td><td>147</td></tr>
<tr><td>Right Arm</td><td>319</td></tr>
<tr><td>Left Arm</td><td>588</td></tr>
<tr><td>Right Leg</td><td>30</td></tr>
<tr><td>Left Leg</td><td>31</td></tr>
</table>
Per the RWP, the Administrative Dose Limit for the dive was 500 mrem.
The diver's TLDs were processed and the results are given below
<table>
<tr><th>TLD Location</th><th>TLD Result (mrem)</th></tr>
<tr><td>Chest</td><td>135</td></tr>
<tr><td>Right Arm</td><td>403</td></tr>
<tr><td>Left Arm</td><td>673</td></tr>
<tr><td>Right Leg</td><td>30</td></tr>
<tr><td>Left Leg</td><td>34</td></tr>
<tr><td>Head</td><td>216</td></tr>
</table>
Does the situation described above constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?

Response:
NEI 99-02 identifies the dose value used as a screening criterion to identify an unintended exposure occurrence as 100 mrem. The administrative dose guideline was established in the RWP as 500 mrem. Since the ED was functional and read 588 mrem, the screening criterion in 99-02 was not exceeded.</td><td>7/22 Introduced
8/18 Additional information required
Referred to HP group
10/13 Licensee providing additional information to HP group</td><td>Brunswick</td></tr>
<tr><td>39.1</td><td>IE03</td><td>Question:</td><td>8/18 Introduced</td><td>Brunswick</td></tr>
</table>

TempNo.	PI	Question/Response	Status	Plant/ Co.
		On June 23, 2004, condenser waterbox level and temperature readings on the Unit 1 and 2 main condensers indicated partial blockage of the waterbox intake debris filters. The cause was an influx of gracilaria, which is a marine grass found in the river water that is the circulating water intake supply to the plant. Subsequent backwashes of the debris filters were successful at restoring waterbox level and temperature readings to the normal band, except for the 2B-South waterbox, which is one of four waterboxes of the Unit 2 main condenser. An extended backwash was unsuccessful in restoring its readings back to normal. Debris is removed prior to entering the circulating water intake bay by traveling screens with spray nozzles. The 2B-South debris filter is directly downstream from the 2D traveling screen. Investigation of this event found that the spray nozzles for the 2D traveling screen had more fouling than the other spray nozzles. The 2D traveling screen was able to adequately remove normal debris loading, but was not as effective as the other spray nozzles in removing the debris during the large influx of gracilaria. A decision was made on June 24, 2004 to reduce power to about 53% and isolate the 2B-South waterbox to clean its debris filter. The decision to reduce power within 24 hours was based on several factors, such as reduced condenser efficiency, the potential for additional debris filter clogging, and a reduction in reactor water chemistry due to elevated condensate demineralizer resin temperatures. It was also based on input from work management, operations, and the load dispatcher. The 2B-South waterbox was successfully cleaned during the downpower and reactor power was restored to normal operating conditions. <u>This was an anticipated power change in response to expected conditions.</u> Operating experience has shown that the plant is susceptible to large influxes of gracilaria when the salinity level in the river water is elevated. For example, gracilaria problems were correlated with high salinity levels in 2002, which led to high vulnerability conditions. In addition, during another influx of gracilaria, a downpower was required in August, 2001 to clean the 1A-South debris filter. In response to experience over the past 5 years with gracilaria and other intake canal debris, modifications are being implemented at the river water intake diversion structure, which is the first barrier for intake debris, to improve the debris removal capability. In response to the influx of gracilaria, the plant implemented compensatory actions for a "High Vulnerability" condition in the intake canal. These actions include manning the diversion structure round-the-clock for manual debris removal, increasing screen wash pressure, and staging fire hoses at the traveling screens, if needed, to assist in removing debris. During the June 23 event, all four waterboxes on Unit 1 and three of four waterboxes on Unit 2 were managed within normal operating levels. <u>The power change was proceduralized.</u> The plant operating procedure for circulating water directs a power reduction to isolate a waterbox and clean the debris filter if an abnormally high differential pressure exists after debris filter flushing has been completed. <u>The influx of gracilaria was not predictable greater than 72 hours in advance.</u> Although the biology staff has found that high salinity levels in the river water make the conditions for a gracilaria release favorable, it is not possible to predict when an excessive influx will occur. The compensatory actions taken for a high vulnerability condition have usually been effective in preventing debris filter clogging. Should this event be counted as an unplanned power change? Response: No, the event should not be counted as an unplanned power change. The increased accumulation of gracilaria in the river water was anticipated due to operating experience with high salinity levels in the river water, but the timing of the gracilaria release into the intake canal could not be predicted with certainty. In addition, the response to the condenser level and temperature conditions is proceduralized.	9/16 On hold for more information	
39.2	EP03	Question: If a licensee makes a change in ANS testing methodology, when can that change be used in the ANS PI calculation?	8/18 Introduced. To be discussed at 9/1 EP	NRC

TempNo.	PI	Question/Response	Status	Plant/ Co.
		Response: ~~The~~Any change in test methodology shall be reported as part of the ANS Reliability Performance Indicator effective the start of the next quarterly reporting period. A licensee may change ANS test methodology at any time consistent with regulatory guidance. For the purposes of the Performance Indicator, only the testing methodology in effect on the first day of the quarter shall be used for that reporting period. Neither successes nor failures beyond the testing methodology at the beginning of the quarter will be counted in the PI. However, performance during actual siren activations that utilize the nuclear power plant's ANS activation system shall be included in the PI data. NEI 99-02 requires that the periodic tests be used in developing the Performance Indicator. Pg 94, lines 12-13, states that: "Periodic tests are the regularly scheduled tests..." Therefore, a reporting period (quarter) starts with a sequence of regularly scheduled tests for that quarter. If a licensee determines that testing methodology should be changed, the plan/procedure directing the periodic tests should be revised and screened in accordance with the licensee's change. If the change in ANS test methodology is considered to be a significant change per FEMA requirements, the change is required to have FEMA approval prior to implementation. This FAQ will take effect 1/1/05 and apply to siren testing after 1/1/05.	public meeting 9/16 Tentative Approval 10/13 Tentative approval.	
40.1	EP03	Question: Catawba Nuclear Station has 89 sirens in their 10-mile EPZ; 68 of these are located in York County. Duke Power's siren testing program includes a full cycle test for performance indicator purposes once each calendar quarter. On Tuesday, September 7, 2004, York County sounded the sirens in their county's portion of the EPZ to alert the public of the need to take protective actions for a Tornado Warning. Catawba is uncertain whether to include the results of the actual activation in their ANS PI statistics. The definition in NEI 99-02 does not address actual siren activations. In contrast, the Drill/Exercise Performance (DEP) Indicator requires that actual events be included in the PI. Should the performance during the actual siren activation be included in the Alert and Notification System (ANS) Performance Indicator Data? Response: Yes. Performance during actual siren activations that utilize the nuclear power plant's ANS activation system shall be included in the PI data. The purpose of the ANS Performance Indicator is to monitor the reliability of the offsite ANS, a critical link for alerting and notifying the public of the need to take protective actions. In this case, the system was performing its intended function of alerting the public of the need to take protective actions. This FAQ will take effect immediately for Catawba. For all other plants it will take effect on 1/1/05 and apply to siren testing after 1/1/05.	10/13 Introduced and Tentative Approval. Response text to be revised.	Catawba
40.2	MS02	Question: As discussed in NEI 99-02 (Revision 2), licensees reduce the likelihood of reactor accidents by maintaining the availability and reliability of mitigating systems – systems that mitigate the effects of initiating events to prevent core damage. The Harris Nuclear Plant (HNP) is actively pursuing measures to reduce mitigating system unavailability, such as those discussed below pertaining to High Head Safety Injection (HHSI) unavailability. At the Harris plant, the Essential Services Chilled Water (ESCW) system is a support system (room cooling) for the HHSI system. The HHSI system consists of three centrifugal, high-head pumps, each housed in its own room. HNP Engineering recently analyzed the effect of a loss of ESCW on HHSI availability by performing a room heatup calculation. This analysis showed that a train of HHSI can be maintained available even without the normal room cooling support system (ESCW) for a period greater than the PRA model success criteria (24 hours) through the use of a substitute cooling source powered by a non class 1E electric power source as allowed for in NEI 99-02, Page 37, Lines 27-35. It is important to note that: 1) a HHSI train utilizing the substitute cooling source will be considered Inoperable, 2)	10/13 Introduced	Harris

TempNo.	PI	Question/Response	Status	Plant/ Co.
		only one HHSI train at a time will utilize a substitute cooling source, and 3) the length of time that HHSI is required following a design basis accident is not specified in the FSAR. Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria with a substitute cooling source, the Harris plant considers it available when calculating the NRC's Safety System Unavailability performance indicator. HNP and the resident inspector are not in agreement with respect to how to interpret the definition of unavailability (Page 23, Line 29). Specifically, in this instance, can a safety system train be considered available if it successfully meets its PRA model success criteria or must it satisfy its design basis requirements (long term cooling) to be considered available?		
		Response: A safety system train may be considered available if it successfully meets its PRA model success criteria. Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria with a substitute cooling source, it can be considered available when calculating the NRC's Safety System Unavailability performance indicator.		
40.3	MS04	Question: The Safety System Unavailability Performance Indicator for BWR Residual Heat Removal (RHR) Systems monitors: • the ability of the RHR system to remove heat from the suppression pool so that pool temperatures do not exceed plant design limits, and, • the ability of the RHR system to remove decay heat from the reactor core during a normal unit shutdown (e.g., for refueling or servicing). Perry Technical Specifications require an alternate means of decay heat removal (DHR) to be available when removing an RHR system from service. Technical Specifications do not restrict the options for an alternate decay heat removal system to specific systems or methods. The Bases of Technical Specifications for LCO 3.4.10, RHR Shutdown Cooling System - Shutdown, Required Action A.1 state, "The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System." During the repair of Emergency Service Water (ESW) Pump B, an Off-Normal Instruction with an attachment for "RPV Feed And Bleed With ESW Not Available" was credited as an alternate decay heat removal method for the inoperable RHR system. The referenced procedure takes reactor water from the RHR system shutdown cooling flowpath and directs it to the main generator condenser which acts as the heat sink. The condensate and feedwater systems return the cooled water to the reactor. Reactor temperature is limited to 150°F for this alternate DHR method. The heat removal capability of this method was demonstrated by calculation before being credited. Does the Perry reactor feed and bleed methodology described above constitute an "NRC approved alternate method of decay heat removal" as referenced in NEI 99-02 above?	10/13 Introduced	Perry
		Response: NEI 99-02, "Systems Required to be in Service at All Times" states, "For RHR systems, when the reactor is shutdown with fuel in the vessel, those systems or portions of systems that provide shutdown cooling can be removed from service without incurring planned or unplanned unavailable hours under the following conditions: • RHR trains may be removed from service provided an ***NRC approved alternate method*** of decay heat removal is verified to be available for each RHR train removed from service. The intent is that at all times there will be two methods of decay heat removal available, at least one of which is a forced means of heat removal". ***(Emphasis added.)*** The response to FAQ ID-145 for PI MS04 Residual Heat Removal System Unavailability (Posted 04/01/2000) parenthetically defines an NRC approved method as "an alternate method allowed by Technical Specifications." Since the Bases of Technical Specification only require that the system be capable of maintaining or reducing		

TempNo.	PI	Question/Response	Status	Plant/ Co.
		temperature and since they do not limit the options to the Reactor Water Cleanup System, the feed and bleed methodology is acceptable as an alternate method of decay heat removal. Thus, the reactor feed and bleed alternate decay heat removal method described above is an NRC approved alternate method.		
40.4	MS03	Question: At 1730 on September 10, 2004, BVPS Unit 1 experienced an automatic start of the turbine driven auxiliary feedwater (TDAFW) pump due to the failure (open position) of the turbine steam supply "B" train trip valve. The steam supply configuration is a single steam supply line with a motor operated valve (MOV) that branches into two parallel supply lines, each of which contains a trip valve. The MOV is normally open and the opening of either trip valve will result in a start of the TDAFW pump. The crew attempted unsuccessfully to close the "B" trip valve from the control room. At 1732, the MOV was shut and direction given to the control room operator in the form of written instructions to open the MOV if the TDAFW pump was required for feeding the steam generators. The written instructions were provided on a Maintenance Rule Availability Restoration Procedure form that is approved by a Senior Reactor Operator. The TDAFW pump was declared Tech Spec inoperable, but maintained available because it could be promptly restored from the control room (i.e. open the MOV) by a qualified operator without diagnosis or repair, consistent with the guidance in NEI 99-02, Revision 2. It was subsequently determined that the cause of the "B" valve opening was a failure of a card in the Solid State Protection System which only affected the "B" train valve. In this scenario, can credit be taken for manual operation action to maintain the TDAFW pump available? Response: Yes. On page 31, Additional Fault Exposure Considerations, NEI 99-02 Revision 2 states that "operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e. the restoration actions are virtually certain to be successful during accident conditions)".	11/18 Introduced	Beaver Valley
40.5	IE02	Question: NEI 99-02R2, Pages 15-16, states: "*Loss of the normal heat removal path:* when any of the following conditions have occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path: ... failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure" ... The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path... *Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported."... "*Example of loss of turbine bypass capability:* sustained use of one or more atmospheric dump valves (PWRs)... "*Examples that do not count:* ...partial losses of condenser vacuum or turbine bypass capability after an unplanned scram in which sufficient capability remains to remove decay heat..." On June 4, 2004, Unit 3 was manually tripped due to a heavy influx of red sea grass on the intake to the circulating water pumps. This resulted in securing of 3 of the 4 circulating water pumps. Following the trip, one circulating water pump remained in service and maintained normal condenser vacuum. However, approximately 5 minutes post-trip the Steam Bypass Control System began to not function as designed in auto (later determined to be a faulty permissive channel), and the operators choose to transfer to the Atmospheric Steam Dump Valves (ADVs) to control RCS temperature. The MSIVs remained open and one quadrant of the condenser remained available. Since ADVs are a procedural option to use, and they were working as designed, the choice to look into whether or not the SBCS control valves would function in manual was not pursued. Since the problem with the SBCS was in the permissive	11/18 Introduced	SONGS

TempNo.	PI	Question/Response	Status	Plant/ Co.
		circuit the SBCS valves would have operated as expected from the control room in Automatic (with manual permissive). W believe we meet the requirement for a normal heat removal flow path, and the use of the ADVs were elective on the part of the Operators. In summary, there was not: (1) a complete loss of all main feedwater flow; (2) insufficient main condenser vacuum to remove decay heat; (3) complete closure of at least one MSIV in each main steam line; nor (4) failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure. Nevertheless, since there was prolonged operation of the ADVs, is this considered a loss of turbine bypass capability and therefore a loss of RCS heat removal? Response: No, operation of the ADVs alone does not constitute a SCRAM with loss of normal heat removal. Therefore the event does not count as an unplanned SCRAM with loss of normal heat removal, because: (1) Operators electively used the ADVs in lieu of the SBCS; (2) MSIVs remained open; (3) One quadrant of the condenser was available; and The SBCS was capable of performing its intended safety function in manual.		
40.6	BI02	Question: NEI 99-02R2, Page 80, lines 33-34 states: "For those plants that do not have a Technical Specification limit on Identified Leakage, substitute RCS Total Leakage in the Data Reporting Elements." The RCS total leak rate at SONGS has historically been approximately 0.1 gpm with the identified leakage being approximately one-third of that value (i.e., ~0.03 gpm). Due to low leak rate calculations, instrument uncertainties, and computer modeling, when the total leak rate was less than 1 gpm the identified leak rate equaled or exceeded the total leak rate 55 times from January 2001 to May 2002. Since identified leakage cannot exceed total leakage, SONGS stopped calculating identified leakage if total leakage was less than 1 gpm. The PI reporting requirement is the maximum monthly value of ***identified leakage*** but since we do not calculate this unless it is greater than or equal to 1 gpm, we have reported ***total leakage*** with an appropriate comment (stating this each month). Even though we have a Technical Specification limit on identified leakage [10 gpm], we have opted to report the more conservative value of total leakage. Is this acceptable? Response: Licensees may elect to be conservative and over-report the total leak rate in lieu of the identified leak rate. However, use of the total leak rate in lieu of identified leak rate must be noted in the Comment Section of the B02 PI data submittal.	11/18 Introduced	SONGS
40.7	MS04	Question: Appendix D BFN 1 needs to remove blanks installed in spectacle flanges in RHR service water piping on the A and C trains to restore service water flow capability to the 1A & 1C RHR heat exchanger as part of BFN 1 restart test and system turnover. To remove these system boundary blanks, the service water to the related U2 and U3 RHR heat exchangers will have to be removed from service. The U2 and U3 RHR system each contain 2 100% capacity RHR headers each with two 50% capacity heat exchangers. The heat exchangers are paired as A & C in one header and B & D in the other. The U1 restoration work is planned such that during time the A RHR heat exchanger on U2 and U3 is out of service, the service water supply to the C heat exchangers will remain available. When the C RHR heat exchanger on U2 and U3 is out of service the service water to the A heat exchangers will remain available. The work to remove the blanks can easily be performed within the Tech Spec AOT of 30 days for an RHRSW Heat Exchanger. The work is planned to take approximately 34 hours per heat exchanger train. This potential out of service time would equate to approximately 5% of the available hours to the green threshold for each unit. This FAQ seeks approval to exclude the unavailability on the U2 and U3 A & C trains of RHR due to support system unavailability during this planned Unit 1	11/18 Introduced	Browns Ferry

TempNo.	PI	Question/Response	Status	Plant/ Co.
		restart activity. Can a one time site specific exemption be granted to exclude from the ROP SSU RHR PI the planned unavailability on BFN U2 and U3 A & C trains that result from the BFN 1 RHR service water restoration activities? Response: Unavailability need not be counted against the U2 and U3 during the U1 RHR Service water restoration activities since this is a one time RHR support system unavailability event that can be contributed solely to a planned BFN U1 restart activity		
40.8	MS03	Question: NEI 99-02, pg 33 states that fault exposure is not taken for failures due to a design deficiency that was not capable of being discovered during normal surveillance tests and that these failures are amenable to evaluation through the NRC Significance Determination Process. If a failure occurs due to a combination of historical procedural and physical design deficiencies, should the unavailable hours be counted as fault exposure hours? A Unit 1 condensate storage tank (CST) low-level instrumentation surveillance test (ST) was in progress, which transfers suction from the CST to the Suppression Pool (SP), with the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems in the standby mode. During the suction path swap-over, a hydraulic transient occurred which caused an unexpected RCIC low pump suction pressure turbine trip. RCIC was declared inoperable and unavailable. No HPCI alarms or trips were observed. The cause of the RCIC failure was voids in the suction piping for both of the RCIC and HPCI systems due to a combination of physical and procedural design deficiencies. A portion of the RCIC pump suction piping and the HPCI SP suction check valve bonnet were not designed with a vent path and the HPCI fill and vent procedure did not make use of a vent on SP suction piping between the HPCI SP suction check valve and the HPCI outboard isolation suction valve. The presence of air voids in the system could not have been identified during previous surveillance testing or discovered by other mechanisms. The air voids and the design and procedural deficiencies were not identified until troubleshooting and evaluation of the event. The potential for air voids to go unvented had existed since the Unit 1 initial plant startup in 1986. The CST low-level ST in progress at the time of the event involved HPCI components with no testing criteria that would have identified a RCIC problem. This ST had been performed on several occasions with no RCIC system transients or alarms. In addition, numerous HPCI and RCIC system pump valve and flow tests and system functional tests had been performed with no indication of voids or hydraulic perturbations that would have identified the design deficiency. This was the first time that conditions were aligned such that the transient could occur. The trigger for the event was a pressure wave developed in the common HPCI/RCIC suction piping during HPCI valve stroking with sufficient magnitude to meet the RCIC low suction pressure trip point. Had the HPCI procedure fully utilized all available HPCI system vent paths or had the HPCI and RCIC system valves and piping been provided with physical vents and procedural guidance in the design, then the transient would not have occurred. The NRC representative believes that the cause of the event included deficiencies beyond design deficiencies that exclude it from consideration as a design failure and therefore should be counted in the PI. The station disagrees with this interpretation and believes that the issue is being adequately assessed through SDP that all design deficiencies ultimately have a human error component, and that FAQs 316 and 348 support this position. Response: No. Based upon the NEI 99-02 guidance, fault exposure is not taken for failures due to a design deficiency that was not capable of being discovered during normal surveillance tests. Even though the event was caused by a combination of design and procedural deficiencies, the presence of air in the RCIC system is solely due to the inadequate RCIC system design that existed for a long period of time, which could not be detected during normal surveillance testing, and which was identified during diagnostics and analysis.	11/18 Introduced	Limerick

TempNo.	PI	Question/Response	Status	Plant/ Co.

Attachment 7

38.2 Response:

The guidance on page 33 of NEI 99-02 states that the hours a train of either the emergency ac power system or the residual heat removal (RHR) system is required to be available may be estimated by the number of hours in the reporting period. This was based on the assumption that the emergency power system and the RHR system are required to be available at all times. However, in some situations, including some that have become more common recently (e.g. when a plant is defueled or while performing on-line maintenance), the emergency ac power system, the RHR system, or both, may *not* be required to be available. However, the number of hours that a plant is in such conditions is generally very small in comparison to the number of hours in three years. Therefore it is acceptable for licensees to use the period hours as an estimate of the required hours to simplify data collection.

38.3 Response:

Yes. In general, credit for operator actions to restore monitored systems is limited to those situations described in NEI 99-02, page 27, lines 14 through 23, and page 31, lines 8 through 16. (Note that for equipment malfunctions, restoration actions must be performed in the control room.) Exceptions to these requirements may be approved on a plant-specific basis as described in Appendix D, page D-2, lines 19 through 31. The most important issue that differentiates a monitored system from a support system is that NRC approval through an NOED, a technical specification change, or some other means is mandatory for a monitored system (because a monitored system must meet a higher standard than a support system).

Attachment 8

Documentation of Interpretation Issue
Limerick RCIC Event NEI 99-02 FAQ
Rev – 11/01/04

Supplemental Information:

Prior to the event, on February 12, 2004, maintenance was conducted on the RCIC pump that drained the pump suction piping. The restoration from this maintenance did not vent a section of the RCIC suction piping associated with the abandoned RHR steam-condensing mode due to lack of a vent path. The RCIC suction pressure instruments are located on this section of suction piping (See Attachment 1). Similar RCIC pump maintenance activities were conducted on June 2, 2003 and in 1998. The CST low-level surveillance was performed on several occasions during the interval between this maintenance and the refueling outage (which began on March 1, 2004). These tests did not cause a RCIC turbine trip or actuation of the high and low pump suction pressure alarms.

During the refuel outage in March 2004, the HPCI pump suction was drained. HPCI fill and vent was completed on March 14, 2004, but the fill and vent procedure did not include venting the suppression pool suction line section between the check valve and the outboard suppression pool suction valve. This was a procedural deficiency, which existed since 1997 when the process for venting the pump suction piping changed from being done through clearance and tagging to a procedure. The original clearance and tagging process for venting was also reviewed and found to have only general guidance with no definitive steps to ensure that this section of piping was properly vented. Based on this review, it could not be determined if the methodology for venting the HPCI suppression pool line section of system suction piping had ever been properly performed.

Also during the March 2004 Unit 1 refueling outage, a design change was implemented that replaced the motor operator and gear set on the HPCI inboard suppression pool suction valve, HV-055-*F042, and the valve position was changed from normally closed to normally open. The valve stroke time was also reduced by this modification.

During Unit 1 startup from the outage, on March 19, 2004, the Unit 1 HPCI Pump, Valve and Flow (PV&F) Test, ST-6-055-230-1, was conducted for the first time after making the changes to the system configuration during the outage. It is believed that the conditions required for the transient were established during this HPCI system testing. At that time, a low flow condition was established through the HPCI suppression pool suction check valve during the 920-psig surveillance, and the check valve was likely not fully closed when the surveillance was concluded. Also, this was the first occasion that opened both the modified HPCI pump inboard suppression pool suction valve and the outboard HPCI pump suppression pool suction valve following the HPCI PV&F test. The investigation determined that if the check valve is open when the transfer to the suppression pool occurs, a reverse flow to the suppression pool is briefly present until the check valve closes. When the check valve closes, a pressure wave is created in the associated piping including the shared CST suction line. The magnitude of the reverse flow and resultant pressure wave is exacerbated by the reduced stroke time of the HPCI inboard suppression pool suction valve.

RCIC was operable when reactor pressure exceeded 150 psig on March 18, 2004 at 04:43 hours and remained operable until completion of the HPCI 920 psig surveillance on March 19, 2004 at 14:08 hours. The HPCI alignment to the suppression pool suction path in the low flow mode during the 920-psig surveillance likely resulted in the HPCI suppression pool suction check valve being not fully closed at the conclusion of the test. RCIC was likely inoperable from this time until the event on April 20, 2004 at 02:45 when the Unit 1 CST low-level instrumentation test was performed, and system was aligned to take suction from the suppression pool. The RCIC turbine trip was reset at 02:51 hours and RCIC remained operable from this point. This resulted in exceeding the TS 3.7.3 RCIC 14-day allowable outage time (AOT) for RCIC inoperability and 756.7 hours of fault exposure for the RCIC indicator.

Fault exposure applies because if RCIC had been called upon to perform its safety function during the event, RCIC would have tripped during the swap to the Suppression Pool (HPCI swaps at the same time and this would have resulted in a RCIC trip). Since RCIC would have tripped, it is considered unavailable. Restoration of RCIC from this trip signal is normally performed within a few minutes, from the MCR, using procedures that involve quick and simple operator actions, and taking manual control the RCIC turbine. However, RCIC cannot be considered available with these operator actions because NEI-99-02 guidance does not allow credit for operator actions using manual control of the RCIC turbine.

After the event, at 21:29 hours on April 20, 2004, the surveillance was repeated with additional instrumentation installed. No abnormalities were noted during this test. The two RCIC suction pressure transmitters were then vented. The first transmitter had no air in the line, and the second had minimal air in the line. On April 21, 2004, at 00:53 hours, Unit 1 HPCI suction was aligned to the suppression pool to eliminate the transient initiator.

Between April 22 and May 21, 2004 air was vented from Unit 1 and Unit 2 HPCI and RCIC suction piping and testing was performed to confirm the mitigating effect of the venting activities. Air was vented from the HPCI suppression pool suction piping between the check valve and the outboard suction valve, the bonnets of the HPCI suppression pool suction check valves, and the RCIC CST suction piping associated with the abandoned RHR steam-condensing mode. This venting was accomplished in part by loosening valve packing and breaching piping flanges. In general, testing confirmed that the pressure perturbation was reduced in magnitude after each venting activity.

On May 6, 2004 damping was added to the Unit 1 RCIC pump suction pressure instruments. The long-term corrective action is a modification, which will provide proper venting of the abandoned RHR steam condensing mode piping, and a modification to the HPCI pump suppression pool suction check valve bonnets during the Unit 2, 2005 and Unit 1, 2006 refuel outages.

Based on the Phase III SDP results, the NRC has determined that they will conduct a PI&R sampling inspection of the stations system status and corrective actions,

Current NEI-99-02 Guidance:
Guidance for the NRC Performance Indicators for Mitigating Systems is given in NEI 99-02 Rev 2. NEI 99-02 provides guidance on equipment unavailability due to a design deficiency. It states:

"Equipment failures due to a design deficiency will be treated in the following manner:

Failures that are capable of being discovered during surveillance tests: These failures should be evaluated for inclusion in the equipment unavailability indicators. Examples of this type are failures due to material deficiencies, subcomponents sizing/settings, lubrication deficiencies, and environmental degradation problems.

Failures that are not capable of being discovered during normal surveillance tests: These failures are usually of longer exposure time. These failures are amenable to evaluation through the NRC Significance Determination Process and are excluded from the unavailability indicators. Examples of this type are failures due to pressure locking/thermal binding of isolation valves or inadequate component sizing / settings under accident conditions (not under normal test conditions). While not included in calculation of the unavailable indicators, these failures and the associated hours should be reported in the comment field of the PI data submittal."

FAQs 316 and 348 were also reviewed with the following results:

In the case of FAQ 316, a construction error caused a deficiency to go undetected from construction until discovered years later during operator rounds. The guidance concluded "*While not specifically the result of a design deficiency, this construction caused equipment failure was not capable of being discovered during normal surveillance tests and has a long fault exposure periods thus meeting the same criteria as an excluded design deficiency. Its significance, like that of design deficiency, is more amenable to evaluation through the NRC's inspection process.*" The Limerick event is similar in that provisions for properly venting RCIC had not been available since construction, and no indication of an air void problem was detectable through testing until the event on April 20, 2004.

In the case of FAQ 348, an investigation conducted following post maintenance testing revealed that a flow orifice in a recirculation line was partially plugged with corrosion products, most likely introduced when the pump and associated piping were drained for maintenance. The normal suction path when conducting the surveillance testing was from the CST. The alternate water supply was the safety-related service water (lake), which contained the suspended corrosion material. The guidance concluded, *"Failures that are not capable of being discovered during normal surveillance tests are excluded from the unavailability indicators. During performance of the normal surveillance tests described above, CST water is used, and as such, performing the surveillance could not identify that the orifice would clog when lake water was used."* The Limerick event is similar because pump valve and flow operability test for RCIC is normally conducted using the CST supply, which has sufficient head pressure to preclude the low suction pressure trip from occurring. The CST low-level test involved HPCI suction piping with suppression pool supply. Also, similarly the cause of the RCIC system failure could only be determined after further investigation and diagnosis using non-routine testing conditions.

Overall, NEI99-02 Guidance places an emphasis on using the SDP and inspection activities to determine system performance and risk significance rather than from fault exposure conditions which could not be easily detected or which have existed for long periods of time.

Basis for condition that could not have been discovered during Surveillance Testing:

The surveillance test in progress at the time involved a functional test of CST and HPCI components and did not have any testing criteria that would have identified the source of the RCIC system turbine trip and RCIC pump low and high suction pressure alarms. The CST low-level functional test was exited and troubleshooting actions were initiated. During troubleshooting of this event, it was observed that the low pressure spiking (causing the low pump suction pressure alarm/trip) was removed when the RCIC suction steam-condensing mode piping was vented. The condition of air voids present in the suction piping was not identified until troubleshooting and evaluation of the event. The subsequent investigation identified that the presence of voids in the system has existed since Unit 1 initial plant startup in February 1986, and that provisions for properly venting the RCIC system had not been part of the system design.

The CST low level surveillance test had been performed on several occasions during the interval between the maintenance activities in February and the March 2004 refueling outage with no RCIC system transients or alarms. In addition, numerous HPCI and RCIC system pump valve and flow test and system functional tests had been performed with no indication of voids or hydraulic perturbations that would have identified the design deficiency. There was no indication that venting of the system should occur because this had not been an issue in the past. The technical specification for the HPCI and RCIC systems ensure that the systems are vented from the pump discharge to the pump injection valve and does not test or verify if the system suction piping is filled and vented. There are no alarms or other surveillance test that verify proper venting of suction piping. The Quarterly PV&F surveillance tests are limited to verification of the system's ability to provide and maintain full flow injection capability to the reactor under high reactor pressure in response to an accident condition.

The adverse condition could not have been identified during previous surveillance testing or discovered by other mechanisms since this was the first time that conditions were aligned such that the transient could occur. This was the first occasion that opened both the modified HPCI pump inboard suppression pool suction valve and the outboard HPCI pump suppression pool suction valve following the HPCI Pump, Valve, and Flow test. The modified HPCI inboard suppression pool suction valve, HV-055-*F042, is not within the RCIC system boundary, so testing of the HPCI system valve would not have identified a RCIC system problem. Under this unique circumstance of parallel conditions, the design flaw became self-revealing because for the first time, the magnitude of the pressure wave had increased to the point of exceeding the RCIC pump low suction pressure trip point. Had the air voids not been present (i.e., a different design with a vent path in the RCIC steam-condensing mode) the transient would not have occurred. Had the HPCI pump inboard suppression pool suction valve not been modified, the pressure wave may not have been sufficient to meet the RCIC low suction pressure trip point.

Only during trouble shooting and analysis of the event was it discovered that the cause was due to insufficient system venting of the abandoned portions of RCIC piping.

Basis design deficiency:

The Root Cause Team for the event identified one root cause with two contributing causes.

The root cause was a combination of design and procedure deficiencies. A design deficiency resulted in portions of the RCIC pump suction associated with the abandoned RHR steam condensing mode piping not having provisions for venting. Fill and vent procedural deficiencies allowed insufficient venting of air from the HPCI system suction piping.

A contributing cause to the RCIC turbine trip was modification of the HV-55-1F042 during 1R10, which decreased the stroke time of the valve. The team determined that this, coupled with the contributing cause of a slightly open 55-1F045-check valve, might predispose the system for a hydraulic transient.

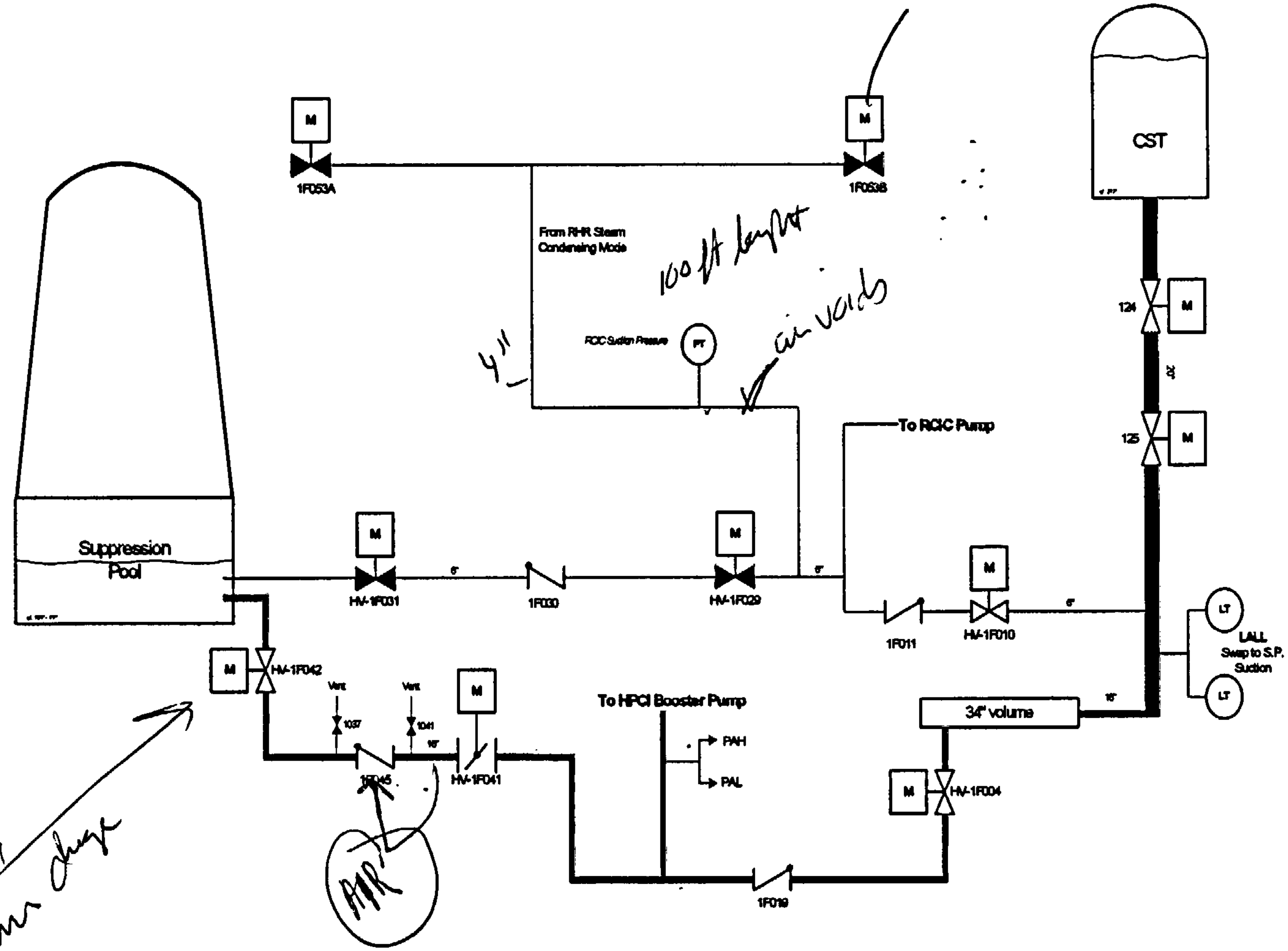
This new system configuration had not existed until the new design configuration was implemented. Although the system was susceptible to the presence of voids and pressure transients since construction, it did not result in a transient until April 2004 because of the new set of conditions at the time of the event. Previous surveillance testing was not subject to the same configuration, hence no similar events have occurred.

Conclusion

When reviewing the Limerick event and NEI 99-02 Guidance as a whole, for conditions which can not be easily detected or which have existed for long periods of time, the emphasis is placed on using the SDP and inspection activities to determine safety system performance and risk significance of the condition over that of using the performance indicator percent unavailability. The Limerick event fits this scenario. Based on these considerations, Limerick's position that the indicator should not be penalized is supported by NEI 99-02 guidance and the station believes that the NRC is already addressing the proper regulatory oversight of the issue through the SDP process.

Known interaction

Attachment 1



100 ft length

air voids

4"

Stroke Fwd charge

AIR

12" piping

Attachment 9

APPENDIX K

MAINTENANCE RISK ASSESSMENT AND RISK MANAGEMENT SIGNIFICANCE DETERMINATION PROCESS

1.0 OBJECTIVE

To determine the significance of inspection findings related to licensee assessment and management of risk associated with performing maintenance activities under all plant operating or shutdown conditions in accordance with Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control."

This guidance does not however directly apply to those licensees who perform qualitative analyses of plant configuration risk due to maintenance activities. When performance deficiencies are identified with qualitative assessments, the inspector should determine significance of the deficiency by an internal NRC management review using risk insights where possible. Use of risk insights may include an independent NRC quantitative risk assessment (e.g., use of plant specific Standardized Plant Analysis Risk model). It is expected that most licensees will perform quantitative assessments for at-power conditions but not necessarily for plant shutdown conditions. In addition, quantitative risk assessments for the large early release frequency (LERF) and external events (e.g., fire, seismic, high winds) risk effects are not normally performed due to the lack of probabilistic risk tools for these effects. For these risk effects, a qualitative assessment is more common and the approach described above should also be used to determine significance.

2.0 BASIS

NRC requirements in this area are set forth in paragraph (a)(4) of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Detailed bases information for this appendix is provided in Inspection Manual Chapter (IMC) 308, "Reactor Oversight Process (ROP) Basis Document, " Attachment 3, Appendix K.

3.0 GENERAL GUIDANCE

The input to the maintenance rule (a)(4) Significance Determination Process (SDP) is an inspection finding that has some degree of significance due to the licensee's underestimate of plant risk or lack of risk assessment from ongoing or completed maintenance activities and/or the licensee's ineffective implementation of risk management actions (RMAs). One of these elements of paragraph (a)(4) requirements must be affected before a licensee performance deficiency exists.

Attachment 1 provides additional guidance including the assumptions and defined terms used in this SDP. Table 1 is used by the resident inspectors to determine the extent of the licensee performance deficiency. Flowcharts 1 and 2 are used to categorize individual inspection findings into one of four levels in the following safety significance color scheme.

Green	Very Low Safety Significance
White	Low to Moderate Safety Significance
Yellow	Substantial Safety Significance
Red	High Safety Significance

It is expected that resident inspectors will work with Senior Reactor Analysts (SRAs) as necessary to assess the significance of maintenance rule a(4) related inspection findings.

4.0 SPECIFIC GUIDANCE

Step 4.1 - Extent of Performance Deficiency Review

The inspectors must use Table 1, "Inspector Screening Checklist" to confirm the extent of the licensee performance deficiency. Although a determination was made that a given finding is of greater than minor significance in IMC 612, Appendix B, the reference to Table 1 confirms that decision and provides clarifying information as needed. If none of the items on Table 1 are applicable, then the inspector must exit this appendix and conclude the issue is of minor significance.

Table 1 - Inspector Screening Checklist

Check if Appropriate	Maintenance Rule (a)(4) Issue	Clarifying Information
	Licensee risk assessment failed to include risk significant SSCs and support systems included in Table 2 of the plant specific Phase 2 SDP risk-informed inspection notebook.	
	Licensee risk assessment failed to consider SSCs such as Residual Heat Removal Systems (PWR and BWR) that prevent or mitigate Interfacing System LOCAs.	
	Licensee risk assessment failed to consider SSCs that prevent containment failure such as containment isolation valves (BWR & PWR), BWR drywell/containment spray/containment flooding systems, and PWR containment sprays and fan coolers.	

	Licensee risk assessment failed to consider imminent severe weather in and around the plant site including potential grid reliability concerns (input obtained from regional transmission system operator).	
	Licensee risk assessment failed to account for any maintenance activity that could increase the likelihood of initiating events such as work in the electrical switchyard increasing the likelihood of a loss of offsite power and RPS testing that could increase the likelihood of a reactor trip.	
	Licensee risk assessment failed to account for the removal or impairment of fire barriers, flood barriers, or seismic restraint.	
	Licensee risk assessment failed to account for any unavailability of a single train of a system (primary or back-up) that provides a shutdown key safety function.	
	Licensee's risk assessment has known errors or incorrect assumptions that has the potential to change the outcome of the assessment.	
	Licensee failed to implement any prescribed significant compensatory measures or failed to effectively manage those measures.	

Step 4.2 - Determination of Actual Risk

The risk deficit for performance deficiencies is determined in an increasing order of magnitude fashion to reflect the amount the risk increases from the plant's zero-maintenance risk due to an inadequate risk assessment. Specifically, the incremental core damage probability deficit (ICDPD) and the incremental large early release probability deficit (ILERPD) are the risk metrics used to evaluate the magnitude of the error in the licensee's inadequate risk assessment of the temporary risk increases due to maintenance activities/configurations. Note that this SDP uses Incremental Core Damage Probability (ICDP) metric rather than ΔCDF (annualized risk increase) used in other reactor safety SDPs. The incremental plant risk (ICDP) is a function of the amount of the time in which the plant configuration change existed. Attachment 1 defines the mathematical formulas for these metrics.

Step 4.2.1 - Licensee Evaluation of Risk

When the inspector has identified that the licensee has performed an inadequate risk assessment, or none at all, the actual maintenance risk configuration-specific core damage frequency (CDF) must first be adequately or accurately assessed. The inspector should discuss the results of the risk assessment with the licensee before proceeding with any further risk assessment. The new risk assessment value may be obtained in several ways including having the licensee perform the omitted maintenance risk assessment; or re-perform the assessment, correcting those errors and/or omissions that rendered the original risk assessment inadequate. It is expected that having the licensee re-evaluate the actual maintenance configuration would be the norm for (a)(4) issues.

Step 4.2.2 - NRC Evaluation of Risk

Alternatively, the inspector may request the regional SRA or the headquarters risk analyst to independently evaluate the risk using the plant-specific SPAR model for the following situations:

a. If the licensee's maintenance configuration change excluded multiple systems.

b. There are notable limitations of the licensee's risk assessment tools (e.g., risk assessment tool is not capable of modeling external events, internal flooding, and/or containment integrity etc.).

c. The qualitative risk assessment contained invalid assumptions and omissions.

d. The risk assessment model is not consistent with the plant PRA.

To request an independent risk assessment, the inspector should provide to the regional SRA the results of the items checked in Table 1. In addition, the following information should be provided:

a. SSCs configuration in the specific time window of concern with actual time of SSCs removed from service and when returned to service

b. Description of testing or other maintenance activities that potentially increased the likelihood of an initiating event

c. Description of actual compensatory actions implemented

d. Licensee's risk assessment

In addition, if the finding involves an outage risk configuration, then the appropriate checklist reflecting the plant shutdown mode from IMC 0609, Appendix G, Attachment 1, should be checked and provided to the SRA.

Step 4.3 - Determination of Risk Deficit

If the licensee did not perform a risk assessment, the risk increase (ICDP) is the product of the incremental CDF and the annualized fraction of the duration of the configuration [i.e., ICDP = ICDF x (duration in hours)÷(8760 hours per reactor year)], where ICDF or $\Delta CDF = CDF_{actual} - CDF_{zero\text{-}maintenance}$

Note that the risk deficit, ICDPD = ICDP when the licensee does not conduct a risk assessment.

For a flawed risk assessment, the risk deficit $ICDPD = ICDF_{actual} - ICDF_{flawed}$

Since licensees are not normally expected to take risk management actions for ICDP < 1.0E-6, the net risk impact can be assessed by subtracting 1.0E-6 from the risk deficit (ICDPD) as determined above prior to determining an SDP color. The safety significance of the licensee's underestimate (or lack of estimate) of the risk is then determined by using flowchart 1. The color of the ILERPD, if applicable, is determined in a similar fashion.

Step 4.4 - Assessment of Risk Management Actions

As discussed in NUMARC 93-01, Section 11.3, "Assessment of Risk Resulting from Performance of Maintenance Activities," and in Appendix A of IP 71111.13, the following categories of appropriate RMAs can be used to control risk associated with a maintenance activity.

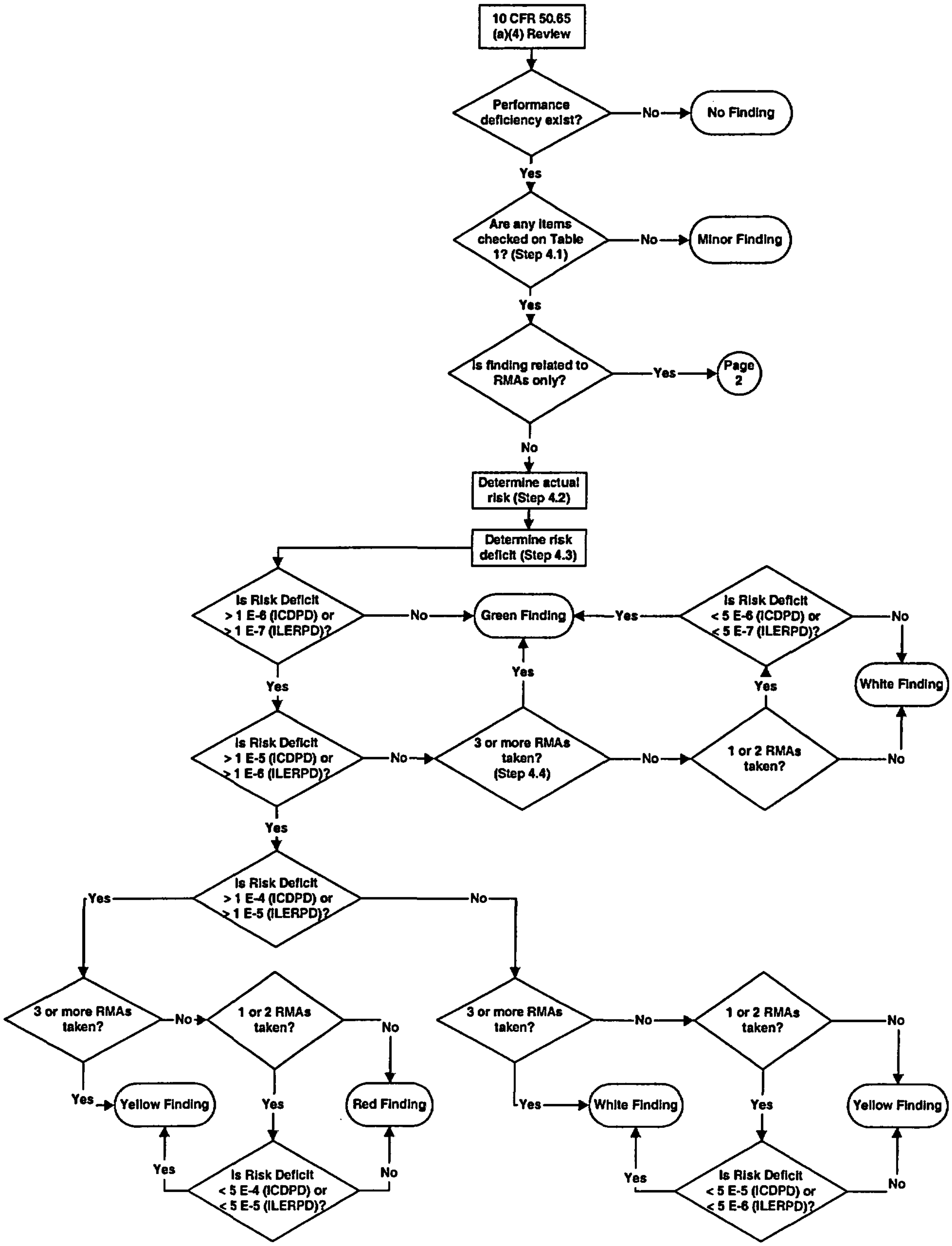
- increasing risk awareness and control
- reducing duration of maintenance activity
- minimizing magnitude of risk increase
- establishing other compensatory measures to provide alternate success paths for maintaining the safety function of the out-of-service SSC (e.g., using diverse means of accomplishing the intended safety function)

Because the risk benefits of these RMAs are generally not quantifiable, the approach chosen for quantitatively determining the significance of failure to manage risk is to assign credit for these actions in reducing the risk impact of the assessed configuration. Therefore, the simple screening rule used in this SDP is to assign a credit of one half order of magnitude reduction in risk to the correctly calculated risk if the licensee effectively implemented one or two categories of the RMAs to control risk. If the licensee effectively implemented three or more categories of the RMAs, an order of magnitude reduction in risk is credited against the actual maintenance risk. This approach allows the significance of failure to manage risk to be expeditiously determined without using quantitative approaches that would likely require intensive resources.

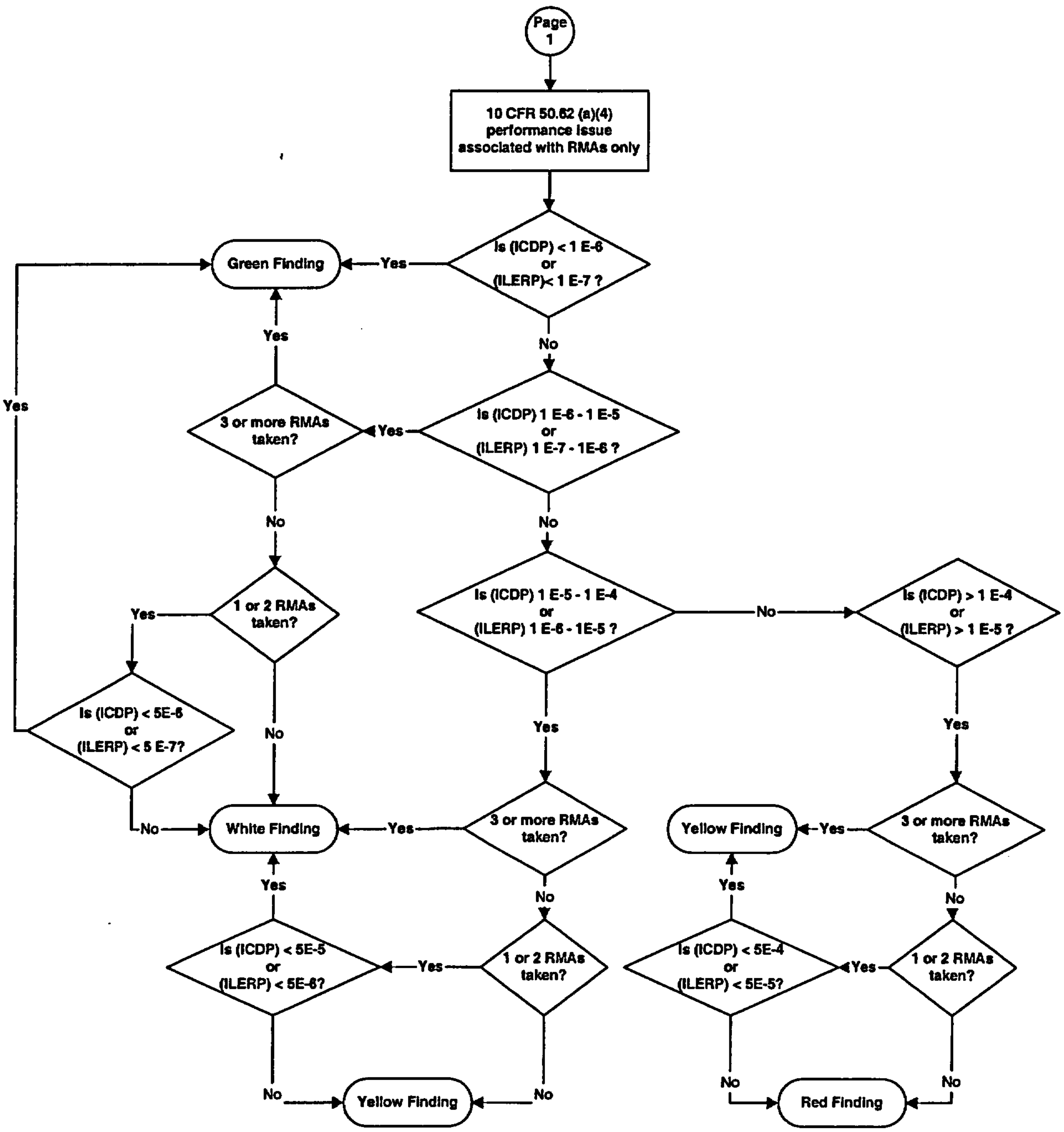
If the risk is inadequately assessed, or not assessed at all, the performance deficiency is processed through this SDP. The resultant failure to take RMAs due to lack of risk recognition merely provides no mitigation of the risk deficits.

When the risk is adequately assessed, the licensee will normally be expected to effectively implement only those RMAs prescribed for the assessed risk by site procedures. Under certain circumstances, specific compensatory measures may also be prescribed by license conditions, technical specifications, notices of enforcement discretion, and/or special commitments, as applicable. The performance deficiency to be processed through this SDP using flowchart 2 would be the licensee's failure to implement one or more RMAs either as prescribed by any of the sets of requirements discussed above. The adequacy of licensee's RMAs should be assessed using the guidance provided in baseline inspection procedure IP 71111.13 and licensee's applicable implementing procedures.

Flowchart 1 - Assessment of Risk Deficit



Flowchart 2 - Assessment of RMAs



ATTACHMENT 1

ADDITIONAL GUIDANCE

The following assumptions and defined terms regarding licensee risk assessments and risk management actions (RMAs) are necessary to understand and efficiently use this maintenance rule (a)(4) SDP evaluation tool.

1.0 RISK ASSESSMENTS AND RISK MANAGEMENT ACTIONS

The intent of paragraph (a)(4) is for licensees to appropriately assess the risks of proposed maintenance activities that will:

- directly, or may inadvertently, result in equipment being taken out of service,
- involve temporary alterations or modifications that could impact SSC operation or performance,
- be affected by other maintenance activities, plant conditions, or evolutions, and/or
- be affected by external events, internal flooding, or containment integrity.

Paragraph (a)(4) requires management of the resultant risk using insights from the assessment. Therefore, licensee risk assessments should properly determine the risk impact of planned maintenance configurations to allow effective implementation of RMAs to limit any potential risk increase when maintenance activities are actually being performed. Although the level of complexity in an assessment would be expected to differ from plant to plant, as well as from configuration to configuration within a given plant, it is expected that licensee risk assessments would provide insights for identifying risk-significant activities and minimizing their durations. In general, the following two types of licensee performance deficiencies in meeting (a)(4) requirements can be defined.

A. Failure to Perform an Adequate Risk Assessment. The failure to perform an adequate risk assessment in accordance with 10CFR50.65 (a)(4) prior to the conduct of maintenance activities includes the following deficiencies which result in underestimating the risk.

   1. failure to perform a risk assessment for maintenance configuration changes.

   2. failure to update a risk assessment for changes in the assessed plant conditions (e.g., changes in maintenance activities or emergent conditions). However, performance or re-evaluation of the assessment should not interfere with, or delay, the operator and/or maintenance crew from taking timely actions to restore the equipment to service or take compensatory actions. If the plant configuration is restored prior to conducting or re-evaluating the assessment, the assessment need not be conducted, or re-evaluated if already performed.

3. failure to perform a complete risk assessment including all affected/involved SSCs within the scope of SSCs required for (a)(4) assessments, and considering (or adequately considering) all plant-relevant plant conditions or evolutions, external events, internal flooding, and/or containment integrity

4. failure to consider maintenance activities which have historically had a high likelihood of introducing a transient leading to an initiating event that would result in risk-significant configurations

5. Improper use of the risk assessment tool or process (i.e., beyond its capabilities or limitations, or under plant conditions for which it was neither designed nor in accordance with site procedures)

6. deficient risk-informed evaluation process for limiting the scope of SSCs to be included in (a)(4) risk assessments as identified by NRC inspection in accordance with IP 62709

7. flawed risk assessment tool or process as identified by NRC inspection in accordance with IP 62709

Underestimating or not estimating the risk of maintenance activities may not significantly increase the expected overall plant risk, in terms of core damage frequency (CDF) or large early release frequency (LERF). However, underestimating the risk may result in lack of risk awareness that could preclude RMAs and allow a high-risk configuration to persist unrecognized and uncompensated. Allowing a high-risk configuration with an unassessed CDF increase to persist longer than necessary, or desirable, will increase the exposure time and hence the incremental (integrated) core damage probability (ICDP) and/or the incremental large early release probability (ILERP) as defined below. Finally, unawareness of unassessed or inadequately assessed risk may allow actions or events to occur that could directly increase risk or hamper recovery from accidents or transients.

Licensees that have adopted RMA color thresholds that are not ICDP or ILERP based, may need to have performance converted to correspond to a probability unit of measure.

B. <u>Failure to Manage Risk</u>. Failure to manage the risk impacts of proposed maintenance activities means a failure to implement, in whole or in part, the key elements of the licensee's risk management program. However, this deficiency will not result in an additional risk increase to the assessed risk of the maintenance configuration in terms of CDF or LERF, unless an event actually occurs that results in additional risk impacts. Measures to minimize the duration of the risk associated with a maintenance activity/configuration are a principal RMA. Nevertheless, failure to implement such measures when they are possible and practicable will allow the ICDP and/or the ILERP to increase further as the elevated risk condition persists. Appropriate and suitable RMAs can only reduce the risk incurred from a given configuration change.

RMAs should be implemented in a graduated manner, commensurate with various increases above the plant's baseline risk, to control the overall risk impact of an assessed maintenance configuration. However, licensees use a variety of methods for categorizing risk significance and managing the risk according to the category.

In Regulatory Guide 1.182, the NRC endorsed the RMA levels or categories/bands prescribed in the revised Section 11 of NUMARC 93-01, Revision 2, and subsequently incorporated in Revision 3 of NUMARC 93-01. These risk bands are defined in terms of the ICDP, making them readily comparable to the risk levels used in determining the significance of the risk deficits. For licensees that have adopted this guidance, normal work controls are allowed by site procedures for ICDPs less than 1 E-6. For ICDPs of 1E-6 or greater, RMAs are prescribed. Section 11 of NUMARC 93-01 states that maintenance risk configurations above ICDP value of 1E-5 should not be entered voluntarily. Site procedures will prohibit this activity entirely or will allow it only with fairly rigorous restrictions that typically include the plant manager's written permission along with extensive RMAs. Site procedures may further define specific detailed RMAs or plans for routinely allowable risk categories as well. It should be noted that when evaluating the adequacy of a licensee's RMAs, the inspector should consider only those actions that could have potential risk implications and required by the licensee's procedures, such as working around the clock, installing backup equipment, and reducing duration of maintenance activity for effective implementation of RMAs.

2.0 DEFINITIONS

The following are definitions of terms used throughout this SDP.

Incremental Core Damage Frequency (ICDF). The ICDF is the difference between the actual (adequately/accurately assessed) maintenance risk (configuration-specific CDF) and the baseline (or zero-maintenance) CDF. The configuration-specific CDF or ICDF is the annualized risk estimate with the out-of-service or otherwise affected SSCs considered unavailable. The term, "Incremental Core Damage Frequency" is also equivalently referred to as delta CDF, or change in CDF.

Incremental Core Damage Probability (ICDP). The ICDP is the product of the incremental CDF and the annual fraction of the duration of the configuration [i.e., ICDP = ICDF x (duration in hours)÷(8760 hours per reactor year)]. Note that the ICDP is sometimes expressed as the integrated or integral ICDP (i.e., the delta CDF or ICDF integrated over the time of its duration which increases as the elevated-risk configuration persists). Figure 1 is a graphical representation of this concept.

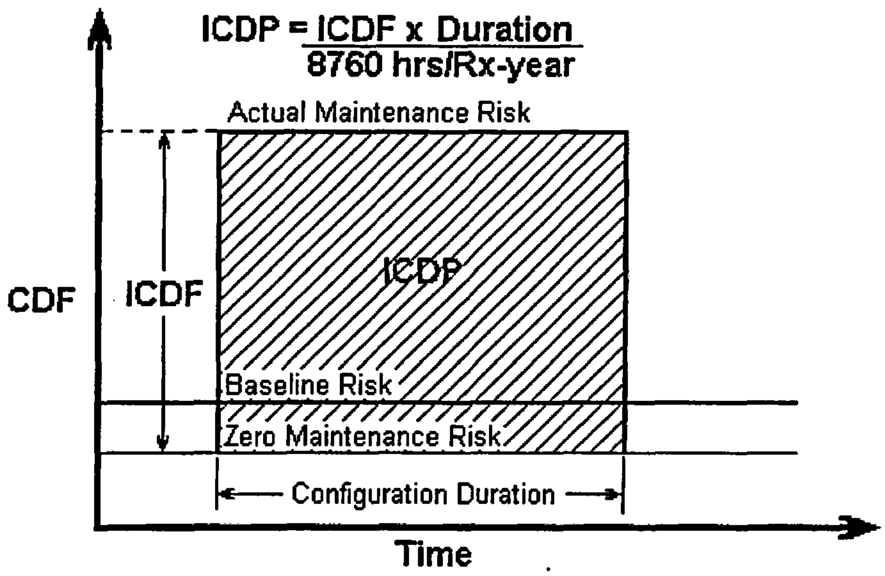


Figure 1 - Relationship of ICDF to ICDP

Incremental Core Damage Frequency Deficit (ICDFD). The ICDFD is that portion of the ICDF defined as the difference between the actual maintenance-configuration-specific CDF (called $ICDF_{actual}$ for purposes of this definition) and the maintenance-related ICDF as originally and inadequately assessed (flawed) by the licensee ($ICDF_{flawed}$). Therefore, the $ICDFD = ICDF_{actual} - ICDF_{flawed}$. Note that if the licensee has failed to assess maintenance risk entirely when required (i.e., there is no licensee risk assessment), then the ICDFD will be equal to the entire value of the ICDF. The safety significance of the ICDFD (i.e., the magnitude of the licensee's underestimate (or lack of estimate) of the risk) is determined by means of this SDP.

Incremental Core Damage Probability Deficit (ICDPD). The ICDPD is the product of the ICDFD and the Exposure (i.e., the annual fraction of the duration of the unassessed or inadequately assessed configuration, or that portion of the annual fraction of the duration of the maintenance configuration during which its risk remained unassessed or inadequately assessed). Thus the ICDPD = ICDFD x (exposure in hours) ÷ (8760 hours per reactor-year). Note that similar to the ICDFD, the ICDPD equals the ICDP when there is no risk assessment, rather than a flawed risk assessment. Note also that Exposure equals Duration if the risk remained unassessed or inadequately assessed for the entire duration of the configuration. The safety significance of the ICDPD (i.e., the magnitude of the licensee's underestimate (or lack of estimate) of the risk (in terms of ICDP)), may also be determined by means of this SDP. Figure 2 is a graphical representation of this concept.

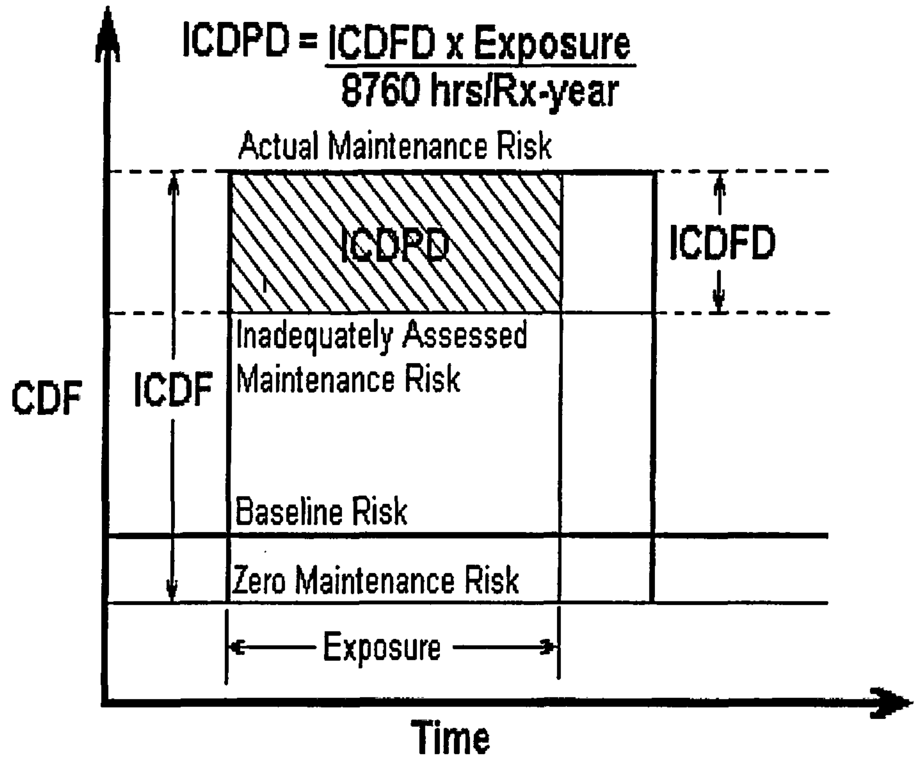


Figure 2 - Relationship of ICDFD to ICDPD

Incremental Large Early Release Frequency (ILERF). The ILERF is the difference between the actual, adequately determined maintenance activity/configuration-specific LERF and the plant's baseline maintenance LERF, if determinable. Note that LERF and ILERF are determinable only if the plant has a Level-II probabilistic risk analysis/probabilistic safety assessment (PRA/PSA) and a risk tool or process capable of quantitatively assessing Level-II risk beyond a qualitative assessment of the impact of containment integrity. If calculated, the ILERF may also be referred to as the delta LERF or LERF difference.

Incremental Large Early Release Frequency Deficit (ILERFD). The ILERFD is used to evaluate the significance of a finding under the following conditions (1) an impact on containment integrity from or concurrent with the maintenance activity occurs, (2) this impact is/was not qualitatively assessed, and (3) the impact is/was quantitatively assessed, but not adequately. Then the ILERFD is meaningful and is that portion of the ILERF defined as the difference between the actual maintenance-configuration-specific LERF (called $ILERF_{actual}$ for purposes of this definition) and the maintenance-related ILERF as originally and inadequately assessed by the licensee ($ILERF_{flawed}$). Therefore, the $ILERFD = ILERF_{actual} - ILERF_{flawed}$. Note that if the licensee has failed to assess maintenance risk entirely when required (i.e., there is no licensee risk assessment) and there is an impact on containment integrity from or concurrent with the maintenance activity, this impact can be neither qualitatively nor quantitatively assessed. Therefore, the

ILERFD will be equal to the entire value of the ILERF. The safety significance of the licensee's underestimate (or lack of estimate) of the Level-II risk (i.e., ILERFD) may also be determined by means of this SDP, if appropriate.

Incremental Large Early Release Probability (ILERP). The ILERP is the product of the incremental large early release frequency (ILERF) and the annual fraction of the duration of the configuration. The ILERP=(ILERF x duration in hours)÷(8760 hours per reactor-year).

Incremental Large Early Release Probability Deficit (ILERPD). The ILERPD is the product of the ILERFD with the annual fraction of the duration of the unassessed or inadequately assessed configuration, or that portion of the annual fraction of the duration of the maintenance configuration during which its risk (in terms of ILERF or ILERP) remained unassessed or inadequately assessed.

NOTE: Although an adequate maintenance risk assessment is expected to include the impact of containment integrity, at least qualitatively, there is no regulatory requirement for a quantitative risk assessment using a Level-II PRA. Paragraph (a)(4) of 10 CFR 50.65 neither prohibits nor explicitly discourages incurring maintenance risk. It only requires that the risk of maintenance activities be assessed (which can be done qualitatively, quantitatively, or, as is often the case, in a blended fashion) and managed.

Loss of Function. This is the condition in which an SSC becomes incapable of performing its intended purpose. This can mean a complete functional failure or impaired or degraded performance or condition such that the affected SSC is incapable of meeting its functional success criteria. Functional success criteria include having the required trains, adequate speed, flow, pressure, load, startup time, mission time, etc. These are defined or assumed in the design and/or licensing bases (i.e., updated final safety evaluation report, license conditions, or technical specifications and/or their bases). For the purposes of determining risk/safety significance, the functional success criteria of particular interest would be those assumed in the plant's PRA and/or the licensee's risk assessment tool. In some cases such as testing, a "lost" function can be promptly restored if restoration actions (a single action or few simple actions)are done by a dedicated local operator.

Zero-Maintenance CDF(Risk). The CDF estimate of plant baseline configuration where all SSCs are considered available.

Baseline CDF(Risk). The CDF from a PRA considering average annual maintenance (preventive and corrective maintenance), and plant specific reliability data (failure rates).

Note that inadequate risk assessment or risk management for work not yet started is not an (a)(4) violation, but it still represents a licensee performance deficiency and may be indicative of deficiencies in previous risk assessments, RMAs and/or in the licensee's (a)(4) program. This SDP is not suited for determining the significance of this type of performance deficiency. This issue will be screened to Green in accordance with Reactor SDP Phase 1 screening.

END

NRC FORM 8C
(7-94)
NRCMD 3.57

COVER SHEET FOR CORRESPONDENCE

USE THIS COVER SHEET TO PROTECT ORIGINALS OF MULTI-PAGE CORRESPONDENCE